CALIFORNIA
ENERGY
COMMISSION

# ELECTRICITY AND NATURAL GAS ASSESSMENT REPORT

DRAFT STAFF REPORT

Prepared in support of the Integrated Energy Policy Report Proceeding (02-IEP-01)

AUGUST 2003
P100-03-014D

Gray Davis, *Governor*

# CALIFORNIA ENERGY COMMISSION

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# ACKNOWLEDGMENTS

There were a number of staff contributions to the project, technical feedback provided during the thirteen public workshops and formal comments that were submitted by interested parties. The ***Electricity and Natural Gas Assessment Report*** staff management team appreciates the analytical efforts, support and public involvement to produce a balanced evaluation of the energy system issues.

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A large group of Energy Commission staff contributed to the project and preparation of the ***Electricity and Natural Gas Assessment Report.*** The management team appreciates the work undertaken by a host of talented individuals. Special recognition is given to:

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The management team is especially grateful to Barbara Crume and Mary Ann Miller for their dedication to organize and manage the many administrative tasks involved for completing this major endeavor.

The management team acknowledges the contributions made by many parties in this proceeding:

American Rivers
Aspen Environmental Group
Association of California Water Agencies
Big Mamas with People Power
Black Mountain Technology
Border Power Plant Working Group
Butte College Small Business Development Center
California Air Resources Board
California Business Roundtable
California Consumer Power and Conservation Financing Authority
California Department of Fish and Game
California Department of Food and Agriculture
California Department of General Services
California Department or Forestry and Fire Protection
California Department of Water Resource
California Hydropower Reform Coalition
California Independent System Operator
California Municipal Utilities Association
California Public Utilities Commission
California Regional Water Quality Control Board
California Resources Agency
California State Water Resources Control Board
California Wind Energy Association
Calpine
Capistrano Bay League of Women Voters
Center for Energy Efficiency and Renewable Technologies
City of Burbank Public Department
City of Glendale
City of Redding
Clean Energy Systems, Inc.
Coalition For Clean Air
Electricity Oversight Board
Encana Gas Storage
Enerland, LLC

Geothermal Resources
Green Power Institute
Independent Energy Producers Association
JBS Energy, Inc.
Kern River
Kern Wind Energy Association
Kessler & Associates
League of Women Voters of the Bay Area
Los Angeles Department of Water and Power
M.Cubed
National Marine Fisheries Service
Natural Heritage Institute
Natural Resources Defense Council
North Baja Pipeline
Novi Industries
Oak Creek Energy Developer
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PG&E Gas Transmission Northwest
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Peninsula Energy Partners
Power Wheel Associates
Public Policy Institute of California
Raven Energy
Redding Electric Utility
Regional Council of Rural Counties
Roseville Electric
Sacramento Municipal Utilities District
San Diego Gas & Electric
San Joaquin Valley Air Pollution Control District
San Mateo County Transportation Authority
Sempra Energy
SoCal Co-Generation Council
Solargenix Energy
Southern California Edison Company
Southern California Gas Company
Stirling Energy Systems
Utility Reform Network
Vulcan Power
Western Area Power Administration
Williams Energy Company

Senate Bill 1389 directs the Energy Commission to work in consultation with other state agencies. The analytical findings include the records and decisions from other energy related proceedings. The Energy Commission also solicited the active participation from the following entities:

- California Public Utilities Commission
- Electricity Oversight Board
- California Consumer Power and Conservation Financing Authority
- Department of Water Resources
- Department of Motor Vehicles
- California Air Resources Board
- California Independent System Operator

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# *Executive Summary*

## Introduction

Over the last two years, the Executive and Legislative branches of California government have stressed the need to revive the stability of the state's electricity and natural gas industry, re-design the market rules to create a workable and competitive system, and restore an incentive system for building needed infrastructure. Progress is occurring in several key areas, such as ideas to re-designing the market structure, ensuring the adequate availability of energy resources, managing costs, re-building regulatory certainty, and developing preferred resource choices. However, further actions are needed to reduce the system's vulnerability to risks of adverse shocks from supply-demand imbalances and price volatility.

In 2002, the Legislature passed Senate Bill 1389, which directed the Energy Commission, in collaboration with other state agencies, to:

- Identify historic and current energy trends,
- Forecast and analyze potential future energy developments, and
- Recommend new policies for current and pressing energy issues facing the state.

California needs a strong and flexible energy infrastructure to meet the unique energy needs of the state. This infrastructure, when coupled with efficient industry performance rules, will ensure that consumers receive reliable, reasonably-priced electricity and natural gas that will promote economic growth, protect public health and safety, and protect the environment. Achieving these goals is complicated by the interrelationship between electricity and natural gas markets.

## Electricity and Natural Gas Infrastructures are Closely Linked

California's electricity and natural gas markets have become closely inter-related as natural gas has become the fuel of choice for electricity generation. The growing electricity generation demand is, in turn, driving the increasing need for natural gas supplies throughout California. The role of natural gas in electricity generation impacts how the natural gas system must be designed and operated.

Natural gas-fired generation has become the technology of preference. Technology advancements over the past decade have enabled power plants to operate more efficiently at lower overall cost and better follow load, that is, increase or decrease output as consumer demand waxes and wanes. Gas-fired generation units can be constructed in many sizes and located either near load centers or in remote locations close to gas pipelines and transmission wires. In addition to these advantages, natural gas comes from regions throughout North

America, which is supplied by a gas market that until recently has been considered as workably competitive.

The inter-related nature of the electricity and natural gas systems also means that price fluctuations in the fuels market directly affect electricity costs. Price shocks or shortages in one market quickly cross over into the other system. When natural gas-fired generation is used extensively to serve summer air conditioning needs, then natural gas providers defer storage injections or even draw down inventories, which are needed to meet next winter's gas heating demands.

As a result, natural gas demand now has two peak periods, summer and winter. These two seasonal peaks challenge the industry's ability to ensure a reliable supply throughout the year, but especially for the winter peak heating demand. As a result, the natural gas market has become more volatile with prices increase in both the natural gas and electricity markets. The price of natural gas and electricity during the winter is also affected by the storage patterns of merchant power plant operators.

Not only are the electricity and natural gas markets inter-connected, but they reach far beyond California's border. Both the electricity and natural gas infrastructure have become increasingly regional in nature. In the case of natural gas, broad national and international developments are being driven by changes in the market and the infrastructure. Consequently, future decisions to build additional natural gas storage, gas pipeline capacity, or an LNG terminal somewhere on the West Coast will affect what consumers pay for electricity. Conversely, other resources can be developed such as renewable generation and electricity demand reductions; these options can influence the price of natural gas.

## Growing Population Increases Energy Demand

In the next decade, California will add five million people to its current population of about 35 million. These five million people will need power and fuel; three-quarters of our electricity growth and all of our natural gas growth will be driven by the need to serve these new citizens.

Commercial growth, spurred by the state's economic expansion, will be the largest user of incremental electricity. But unless demand side management programs reshape current patterns of energy use, this commercial growth may be hampered, and California's commercial rates and bills will continue to be far higher than those of businesses in other western states.

Peak electricity demand rises dramatically in the summer due to air conditioning loads. The difference in demand between an average summer day and a very hot peak day is 6 percent. This difference is equivalent to three years average growth in electricity demand. Electricity use also varies widely over the time-of-day and time-of-year. On a typical day, electricity use may increase 60 percent from the early morning to the afternoon. On a hot summer day, the demand increase can be 85 or 90 percent higher in the afternoon.

To meet these changes in demand, the generation system must be extremely flexible and capable of adding or dropping some facilities quickly to accommodate the wide daily swings, the high summer peaks, weather variability, and economic growth cycles.

Along with adapting to these shifts in demand, the system must accommodate changes in consumer habits and the varying availability of generation, pipelines, transmission lines, storage facilities, and fuel sources. Using risk management tools can help address these contingencies and create a system designed to achieve safe, reliable, affordable energy services.

## Electricity and Natural Gas Demand and Supply: 2003 - 2006

Currently, the physical infrastructure is providing reliable electricity, but at higher consumer prices than in the 1990s. The current capacity levels, in California and the rest of the west, make the reliable delivery of electricity at stable prices likely during 2004 – 2006.

This outlook helps to ensure that spot market prices remain reasonable and minimizes the risk from generation additions and retirements will vary widely from our forecasts. With demand increasing over time, however, this surplus will shrink, leaving ratepayers exposed to potentially higher prices and an increased risk of supply shortfalls. Actions now are underway to firm up new resources by the end of 2006.

Through 2006, natural gas supply and pipelines are sufficient to meet California's annual average needs, but that supply will be delivered at higher prices than in the 1990s. Despite this positive outlook, the system remains vulnerable to seasonal price volatility and difficulties in delivering gas to consumers on the coldest days of the year.

## A Portfolio Approach to Meet Risks and Challenges

An integrated infrastructure has to be flexible enough to deal with both favorable and adverse impacts of risks and uncertainties. The consequences of not planning for adverse conditions are likely to be shortages, while the consequences of not planning for beneficial conditions are likely to be price related. As a result, we place more emphasis on having a system robust enough to deal with adverse conditions.

Shortage risks include the effects of rotating electricity outages or natural gas curtailments. Price risks include exposure to high near-term or long-term power or gas costs. The factors contributing to these risks can not be eliminated. The best we can do is to manage the risks—with the goal of improving California's electricity and natural gas supply had risk management not been attempted.

During this report process, we examined the risk of high and low economic growth, dry hydro conditions, high and low gas prices, and extreme summer temperatures. Between 2004 and 2006, these risks are manageable and do not threaten the reliability of the electrical or natural gas systems, unless unexpectedly large amounts of generation retire before 2006, when the new investor-owned utility and municipal utility procurements come on-line.

As expressed in the ***Energy Action Plan,*** the energy agencies have committed to a "loading order" of preferred resource choices and upgrades to the bulk transmission system to reduce constraints into local reliability areas. Upgrades to the intra-state connector between northern and southern California are underway, and studies have commenced on three inter-state connectors, plus the San Diego and San Francisco local reliability areas. The state is also committed to streamlining the transmission planning and siting processes, which includes increasing community participation because transmission upgrades impact local areas while the benefits extend to regional stakeholders.

## Post 2006 Supply-Demand Balance: Future Choices

Currently, the power and fuel industry spends over a billion dollars every year on modernizing and expanding the infrastructure, including demand-side investments. These investments come in the form of power plants and pipelines, energy efficiency and renewable technologies, transmission lines, and storage facilities. Much of the future infrastructure projects will be expensive and will need to operate for the next forty to fifty years. In using an integrated, portfolio assessment, the options can be balanced against the risks, allowing us to make the best choices.

California now has the time to fashion the basic energy infrastructure in ways that meet multiple public interests. But without an energy policy that provides sufficient resources, ratepayers will be exposed to the renewed risk of high prices and outages by 2007. Acquiring additional resources must begin in 2004, given the time needed in bringing in new generation and transmission resources on-line or building up demand reductions by changing consumer investments and behavior.

## Environmental Performance

The environmental performance of California's power plants is mixed, with some good news on air emissions, while some on-going problems remain in areas like water supplies, water quality, and aquatic habitats.

California is turning the corner on power plant emissions. Due to concerted actions by air regulators, contributions to air inventories from power plants are low on a statewide average basis; though there are specific communities where the relative contribution is greater. The retrofit of older units has reduced their total $NO_x$ emissions 50 percent between 1996 and 2001. Yet, the power and fuel systems do contribute a larger share of greenhouse gases. In both cases, further reductions will be needed to meet long-term environmental goals. These reductions will come from adding demand side management programs and renewable energy to the system, as well as replacing older, less efficient facilities with modern units.

Reducing greenhouse gases will, in the long-term, help slow the impacts of global climate change. In the near-term, California's power system will need to adjust to current global climate impacts, which are evidenced by greater weather variability, hotter days, warmer winters, smaller Sierra snow packs, additional smog, sea level rise, reduced surface water, and earlier spring run-offs. In one instance, earlier runoffs mean that less hydropower is available during a year to help regulate the stability of the electricity system or to serve summer peak demand.

In terms of water supplies, despite the limited availability of freshwater supplies, many power plants still rely on fresh water for power plant cooling even though alternatives are available. As California moves further into the twenty-first century, water supplies will become increasingly constrained, presenting an issue for California's future energy needs.

Power plants continue to affect sensitive aquatic ecosystems on the ocean and in sensitive estuaries. The 21 coastal thermal and nuclear power plants continue to draw water from these ecosystems, using hundreds of millions of gallons of sea water each day.

Hydropower is often considered a "clean" energy resource, yet it too can adversely affect California's water quality. River and stream habitats were degraded and no longer support their former populations of native salmon, trout, or amphibians. Environmental restoration, however, can provide benefits through part of a balanced relicensing review that looks at the multi-purpose functions of dams.

With diverse ecology, California's many endangered wildlife and plant populations are vulnerable to the impacts from future infrastructure projects. Although the effects of one project on terrestrial habitats may be insignificant, the cumulative impacts from many infrastructure projects could be significant and will require further investigation.

## Policy Areas to Watch

From among the many issues discussed in this report, we highlight the following issues as the most current and pressing areas to develop policy. Chapter 1 contains a summary of the findings from which these issues are drawn, and Chapters 2 through 6 contain supporting analysis. Supporting technical documents and the record of the public proceedings are also available to provide stakeholders with a fact based understanding of the challenges and actions necessary to build a sustainable infrastructure.

1. California is in the process of restoring its electricity infrastructure and market. Several activities are underway that should be completed and then linked to maintain an integrated portfolio approach.

For electricity, the key processes include the following:

- Forecasting and planning.
- Investor-owned utilities and municipal utility procurement.
- Demand side management and dynamic pricing proceedings.
- Implementing the renewable portfolio standard.
- Proceedings on market design.
- State and local air district rule-makings and determinations.

2. Meeting resource needs requires dependable construction and operation of thermal power plants, renewable generation and demand side management programs. Uncertainty in power plant long-term contracts, financing, permitting, and construction, and demand side management program development, implementation, and impact must be analyzed and accounted for ahead of time.

   The policy preferences of meeting resource needs first through demand side management and secondly through renewables increases the importance of these programs being implemented to deliver the resources. As these programs translate potential into delivered resources, performance feedback will establish if there are resource gaps that need to be filled by other resources, which also require dependable construction and operation. If new preferred resources are brought on line more quickly or slower than anticipated, then short-term thermal options must be adjusted to balance with expected demand. This report examined uncertainties associated with thermal generation. In the companion *Public Interest Energy Strategies Report*, we propose actions to ensure performance of the preferred resources.

3. Many older power plants have been retrofit with air emission controls, and we expect their continued performance through most of this decade. But California has several marginally performing older units. When these become too costly to compete with new generation, then these plants will retire because either the power plants use too much gas or emission levels cannot be reduced. Some of these plants are necessary for local reliability, and as a consequence, they must be replaced with local resources or upgraded transmission before they are shut down.

   While market forces will lead to these plants' retirement, state agencies must monitor whether sufficient new generation or transmission added where it can function as a substitute.

4. Future transmission planning and permitting must ensure that the transmission system is upgraded while protecting local quality of life.

   Although few new bulk transmission lines have been built in the last two decades, billions of dollars has gone into reinforcing and making maximum use of the current major connections. Among the obstacles to timely transmission development, the most common are related to debates over the need for and benefits of the project, financing difficulties, and local opposition related to environmental and property value impacts.

Efforts are underway on the part of the Energy Commission, California Independent System Operator, and California Public Utilities Commission to develop a common approach to use in the planning and permitting of transmission projects. This approach would serve to determine the value of proposed projects that may be needed to provide economic benefits to the state and see that projects are brought on-line in a timely manner.

5. For the natural gas system, two principal areas of concern are expanding overall supply and using storage to meet seasonal needs.

    - Declining output from several gas-producing basins in the "lower 48" states has been a long-term concern. The state has several supply options to address this concern. New supply options are available in North America, and some additional gas can be gathered within California's borders.

      Internationally, liquefied natural gas is becoming an option as it becomes cost-effective to cool, move, and re-gasify abundant but remote natural gas to load centers. Liquefied natural gas technology, despite the numerous economic and technological uncertainties and risks, may to shift natural gas from a continent-wide market to a world-wide commodity market. Developing shipping access to natural gas producing basins throughout the Pacific and Indian Oceans has the potential for significantly enhancing system reliability, price stability, and environmental performance.

    - Natural gas storage is key to dealing with the seasonal variability needs of end users and electricity generation. Although there appears to be adequate physical storage, state agencies and stakeholders have concerns over whether the market for storage is shifting risks among various natural gas customers in the residential sector, large industrial and commercial, and merchant generators.

6. The state's electrical generation and transmission system affects the natural environment and human communities. While there is good news on air emissions from natural gas-fired power plants, there continue to be serious ongoing impacts to water supplies, water quality, and aquatic habitats from the state's current natural gas, nuclear, and hydro power plants. Impacts to terrestrial ecosystems are well controlled for new power plant cases under Energy Commission jurisdiction, but the impacts from extant and new transmission lines, natural gas pipelines, and non-jurisdictional projects are not as well understood and long-term impacts remain a concern, which require further investigation.

# Chapter 1: Introduction and Findings

## Background

California needs a strong and flexible energy infrastructure that will promote reliable and reasonably-priced energy supplies. Coupled with an efficient market design, this infrastructure will promote economic growth, protect public health and safety, and protect the environment. As the electricity and natural gas systems become increasingly integrated, the system must be able to absorb supply risks, price shocks, volatility and an evolving role for consumers in taking greater control of their energy futures.

Senate Bill 1389 (Chapter 568, Statutes of 2002; Bowen) requires the Energy Commission to adopt an ***Integrated Energy Policy Report*** every two years. The first report is due to the Governor and the Legislature on November 1, 2003. It must provide an overview of major energy trends and issues facing California, including supply, demand, price, reliability, and efficiency. It must assess the impacts of these trends and issues on public health and safety, the economy, resources, and the environment. Finally, it must make policy recommendations to the Governor and the Legislature that are based on an in-depth and integrated analysis of the most current and pressing energy issues facing the State.

Specifically, the legislation directs that the electricity and natural gas assessment shall:

- Assess trends in electricity and natural gas supply, demand, and wholesale and retail prices for electricity and natural gas.
- Forecast statewide and regional electricity and natural gas demand including annual, seasonal, and peak demand, and the factors leading to projected demand growth.
- Assess the potential impacts of electricity and natural gas load management efforts, including end user response to market price signals, to support reliable operations.
- Assess the adequacy of electricity and natural gas supplies to meet forecasted demand growth, natural gas production capability both in and out of state, natural gas interstate and intrastate pipeline capacity, storage and use, and western regional and California electricity and transmission system capacity and use.
- Assess the potential impacts of electricity and natural gas supply, demand, infrastructure and resource additions on the electricity and natural gas systems, public health and safety, the economy, resources, and the environment.
- Assess the environmental performance of the electric generation facilities of the state.
- Assess short-term and long term performance of electricity and natural gas markets to determine if they are adequately meeting public interest objectives including: economic benefits; competitive, low-cost reliable services; customer information and protection; and environmentally sensitive electricity and natural gas supplies.
- Identify impending or potential problems or uncertainties in the electricity and natural gas markets, potential options and solutions, and recommendations.

The Energy Commission is preparing three reports that will provide the analytical foundation for potential energy policy recommendations found in the ***Integrated Energy Policy Report***: the ***Electricity and Natural Gas Assessment Report***; the ***Transportation Fuels, Technologies and Infrastructure Assessment***; and the ***Public Interest Energy Strategies Report*.**

The ***Electricity and Natural Gas Assessment Report*** provides the findings of expected energy infrastructure developments and an analysis of the implications that a number of important uncertainties may present. The primary goal of the report is to identify key factors that may stress the energy infrastructure and to determine if there may be a need for additional development to mitigate potential supply shortfalls in the next decade. Considering that electricity generation is the largest user of future natural gas demand, the energy infrastructure study is also focused on the potential stresses to the natural gas fuel system.

# Integrated Markets

The electricity and natural gas markets are closely inter-related. Both exist to serve our population and economy, so are affected by the same economics, weather, new technologies, and economic growth. But, the advent of natural gas-fired power plants as the dominant new source of power has linked electricity and natural gas markets even more closely. For example, a decision on whether to add natural gas storage can affect what consumers pay for electricity. Conversely, development of renewables generation or electricity demand reductions can influence the demand for and price of natural gas.

These common markets mean that risks and uncertainties are also linked. We have become familiar with the short-term price run-ups which happen when hot temperatures drive up air conditioning use and the demand for natural gas. But there are long-term risks that need to be evaluated in developing a secure and affordable energy infrastructure. These risks include the natural risks of physical supply, demand growth, temperature and weather variations. They also include the human aspects of market design, regulatory uncertainty, and social preferences for how much to mitigate risks.

In this report, we examine the current status and pressing issues which arise from linked issues in the electricity, and natural gas markets. This includes the conventional grid-connected electricity market, and new additions including conventional generation, renewables and energy efficiency.

This ***Draft Electricity and Natural Gas Assessment Report*** is the Energy Commission's initial report of its response to the Legislature's directives. It is organized to follow the logical flow from description to assessment of trends, risks and policy preferences, to findings, conclusions and policy recommendations. These electricity and natural gas assessments address interfuel and intermarket effects to provide a more informed evaluation of potential tradeoffs when developing energy policy across different markets and systems

# Report Development Process

On September 11, 2002, the Energy Commission opened an informational proceeding (Docket No. 02-IEP-01) and designated Commissioner James Boyd, Presiding Member, and Chairman William Keese, Associate Member to oversee the process. The Committee was aided by an inter-agency advisory group consisting of members of nine agencies with energy expertise: the California Public Utilities Commission, California Air Resources Board, Consumer Power and Conservation Financing Authority, Department of Motor Vehicles, Department of Transportation (Cal Trans), Department of Water Resources, California Public Utilities Commission, Office of Ratepayer Advocates; Electricity Oversight Board, and California Independent System Operator.

The Committee held 13 full day workshops on technical subjects. In addition to Energy Commission staff analysis, the Committee heard from 73 stakeholder groups. The inter-agency parties participated in monthly updates and provided additional comment through pre-publication review of staff documents.

This assessment is linked to the *Public Interest Energy Strategies Report*, which examines in more detail the potential for and challenges associated with public interest policy preferences. It is also supported by a panoply of supporting material providing greater technical detail. The attachments to this report include:

1. California Energy Demand 2003-2013 Forecast - #100-03-002,
2. Natural Gas Market Assessment - #100-03-006,
3. Comparative Cost of California Central Station Electricity Generation Technologies - #100-03-001,
4. Aging Natural Gas Power Plants in California - #700-03-006,
5. Upgrading California's Electric Transmission System: Issues and Solutions -#100-03-011,
6. 2003 Environmental Performance Report - #100-03-010,
7. California Municipal Utilities Electricity Price Outlook 2003-2007 - #100-03-005,
8. California IOU Retail Electricity Price Outlook 2003-2013 - #100-03-003,
9. Joint Working Paper on Municipal Utility Resource Adequacy - #100-03-015.

# Summary of Findings

A summary of the findings of each chapter follows.

# Chapter 2: Electricity and Natural Gas Demand Trends

Reliable assessments of the amount, location and timing of demand growth are essential to evaluate the options that can best target California's energy needs.

## Electricity Trends, Overall, by Sector, and Per Capita

Between 2003 and 2013, California will add over 5 million people (a 15 percent increase) and the state economy will grow at double that rate (a 30 percent increase). Given current trends, approximately 10,000 MW (including reserves) of new generation or demand-reducing resources will be needed to serve the growth in the state economy.

Electricity growth is dominated by adding new households and new commercial businesses. Eighty percent of residential energy growth is from adding new homes; only twenty percent is caused by new end-uses. In the residential sector, average electricity use per household has increased one-half percent per year, reflecting higher incomes, larger homes, more homes with air conditioning, and home electronics. This increase in use per household explains only twenty percent of the 1.9 percent per year growth in the residential sector over the last two decades; growth in the number of households explains the rest.

In the commercial sector, businesses have increased electricity use per square foot. Three-fourths of commercial demand growth is due to business expansion – more floor space used by businesses – and one-fourth of growth reflects greater per unit energy use. In the industrial sector, improved productivity has led to greater electricity use per employee; the contribution of the manufacturing to gross state product grew twice as fast as the commercial sector. While a growing population and economy are the fundamental drivers of energy demand, how much demand grows is also affected by the types of businesses that are growing, building and energy efficiency standards and programs, energy prices, and customer behavior.

California uses electricity more efficiently than do other Western states or the U.S. as a whole. This legacy of efficiency standards and programs has kept per capita use constant for many years.

## Daily and Seasonal Patterns of Use

Electricity use varies widely over the time-of-day and time-of-year. In a typical day, use increases 60 percent from the early morning low to the afternoon high. On a hot summer day, this swing is 85- 90 percent. This variable load requires a generation system that is extremely flexible.

Peak electricity demand needles up in the summer due to air conditioning loads. The demand difference between an average summer day and the probability of a 1-in-10 hotter peak day is

6.1 percent, over three times the amount of new demand added each year. Temperature-related variation in demand introduces the need for risk management. We know that hot or cold days are going to happen and have some idea of the frequency of these events, but cannot predict specific future weather patterns.

## Natural Gas Demand Trends

Natural gas end-use growth is slower, increasing at only 0.6 percent per year because there are not many new uses of natural gas. Furthermore, the energy efficiency of new homes and gas appliances has improved over the years. Industry is a heavy user of natural gas, but those industries that use natural gas are not expanding. Growth will be slowest in northern California due to a weak economy and declining industrial demand, but it will be highest in San Diego.

The biggest variable in demand forecasts is economic growth. We estimate that peak demand has a 20 to 40 percent chance of being plus or minus 1,700 MW (3 percent) by 2008, depending on whether the state has high or low economic growth. The swing on potential natural gas use is also 3 percent by 2008. Energy resources must be able to accommodate these variations in the business cycle, again calling for a very flexible system. The analysis of high and low DSM scenarios shows an impact of half the growth impact, not reaching 1,700 MW until 2012.

# Chapter 3: Electricity Infrastructure and Markets

California's electricity and natural gas system must supply as much power and fuel as people demand, at both the immediate moment and location of that demand. The system must accommodate the wide daily swings, the summer peaks, the variability, and the cyclical economic growth described in Chapter 2. This complex interaction among consumer habits, generation, pipelines, transmission lines, storage facilities and fuel sources must be designed to achieve safe, reliable, affordable energy services.

## Gas-fired generation

Gas-fired generation has increased from 25 percent of California's electricity resources twenty years ago to 36 percent of the actual generation used to meet current demand. Under baseline conditions, the gas-fired generation share will increase to about 40 percent by 2013. Since natural gas is now the primary swing fuel, the amount of natural gas that is used in any given year depends on the availability of hydropower. Electricity generation from hydropower resources, including imports, has ranged from a high of 45 percent during the very wet year (1983) to an all time low of 12 percent during the drought in 2001.

Much attention has recently been focused on the age and reliability of the state's gas-fired power plants. These combustion turbines, combined cycles, cogeneration units and steam boilers provide a wide range of services, including baseload energy, following load through its daily swings, and serving as the source of peak capacity that occur only a few times per year. Overall the system has become more efficient as new units are added. Of the 54,675 MW of capacity available to California utilities, 9,369 MW have been added since 2000 and 2,356 MW of older units have been retired.
Many of the older plants still in service can be expected to retire during the remainder of the decade, largely for economic reasons. Careful maintenance and upgrades over their lifetimes have extended their service lives, but they will become increasingly unable to compete with newer plants in the marketplace; 13 percent of the state's gas-fired capacity (3,873 MW) and 9 percent of its gas-fired energy in 2002 came from plants built before 1960.

## 2004 -2006 Resource Adequacy

Currently, the physical infrastructure is up to the task, but at higher consumer prices than those of the 1990s. The current capacity surplus makes the reliable delivery of electricity at stable prices likely during 2004 – 2006. This surplus, combined with reduced reliance on the spot market, facilitates generator participation in the spot market at reasonable prices, and minimizes the risks associated with uncertain amounts of capacity additions and retirements. This surplus will shrink as demand increases, leaving ratepayers exposed to potentially higher prices and an increased risk of delivery interruptions.

## Choices for the Future

California has the time now to fashion its basic infrastructure in ways that meet multiple public interests but, in the absence of an energy policy which guarantees resource adequacy, ratepayers faced the renewed risk of high prices and outages by 2007. Given the lags in bringing new generation and transmission resources on line or building up demand reductions by changing consumer investments and behavior, this acquisition of additional resources must commence in 2004.

Having the electricity and natural gas infrastructure we want requires us to balance our exposure to many interrelated risks—simplified by the terms shortage, price and environmental risks. Shortage risks include the effects of rotating electricity outages or natural gas curtailments. Price risks include exposure to high near-term or long-term power or gas costs. Environmental risks include damaging effects to air quality, water supply and quality, biological resources, climate, etc. The risks can't be eliminated. The best we can do is to manage our exposure to them--with the goal of being better off than if we hadn't attempted any risk management.

## Upgrading and Expanding the Transmission System

As expressed in the ***Energy Action Plan***, California has committed itself to upgrading its bulk transmission system and to reducing constraints in local reliability areas. Upgrades to the intra-state connector between Northern and Southern California are underway, and studies have commenced on three inter-state connectors plus the San Diego and San Francisco local reliability areas. The state is also committed to streamlining its transmission planning and siting processes. Part of this includes increasing community participation, since transmission impacts local areas while the benefits extend to regional stakeholders.

Little new bulk transmission has been built in the last two decades, though billions of dollars have gone into reinforcing and making maximum use of the current major connections. Transmission system planners estimate it takes five to seven years to complete a major upgrade to the bulk transmission system. Demonstrating need, securing environmental permits and rights-of-way, securing financing (for private projects), and time requirements for construction, require that planners anticipate the need for transmission expansion projects ten years and more before these projects are in service.

In California obstacles to timely transmission development are most commonly related to debates over project benefits and the need for the project, project financing difficulties and local opposition related to environmental and property value impacts. Efforts are underway on the part of the Energy Commission, CA ISO and CPUC to develop a common methodology that would be used in the planning and permitting of transmission projects. This planning and permitting process would serve to determine the value of proposed projects that may be needed to provide economic benefits to the state.

# Chapter 4: Natural Gas Infrastructure and Markets

Although electricity generation is only 36 percent of total natural gas use today, it accounts for sixty percent of the next decade's growth. Natural gas end-use growth is slower than electricity demand trends, increasing only 0.6 percent per year since there are not many new uses of natural gas. Furthermore, the efficiency of homes and gas appliances has increased to reduce the overall rate of demand growth. Electricity generation demand for natural gas is driving the growth in natural gas demand in California and the rest of the United States.

Over the past three years, pipeline expansions and additions have made pipeline capacity sufficient to serve California's need through 2006. Beyond this date, annual average capacity is adequate, but peak day conditions could warrant further expansion. The natural gas pipeline market is working and the market design is highly likely to deliver additional cost-effective pipelines, once electricity generation contracts for natural gas are established.

Increasing gas demand in Arizona and New Mexico may absorb a significant amount of the natural gas flowing west from the San Juan and Permian basins. These markets can consume a significant amount of the supply that would otherwise serve Southern California.

Expanding the interstate infrastructure serving the East-of-California markets can alleviate this potential.

Despite the favorable supply outlook, the natural gas system is vulnerable over the course of a year. This vulnerability exists because summer-peaking power plants are increasingly using gas during the time the firms store gas for the winter heating peak season. Recent years have shown that natural gas demand peaks not only in winter, but also in summer due to increasing gas-fired power generation. These two seasonal peaks challenge the industry in its ability to ensure a reliable supply picture throughout the year. Regulators and the industry need to determine how storage capacity can be utilized to achieve the desired supply reliability.

The problem of how much natural gas to store is compounded by the market design issue of who should store. Natural gas is bought by three sets of users – utilities on behalf of end-use customers, electricity merchant generators, and unregulated large end-users that buy their own gas. Utility planning allows for meeting all core consumption during the coldest temperature-day on record assuming that the noncore customers would be curtailed. If merchant generators mismanage their gas supplies, curtailment would harm core customers who need electricity to operate gas heaters.

# Chapter 5: Efficiency, Retail Prices and Environmental Performance

## Efficiency

We can minimize the resources needed to provide usable energy for consumers through three principal techniques: energy-efficient end uses and behaviors that reduce the need for power in the first place, using renewable resources instead of depletable resources, and making the remaining system more efficient. California already has an enviable track record compared to the rest of the U.S. on both how little power we use while supporting economic and population growth, and the lower environmental impacts of the built system. These trends can be extended through the policies supported in this Report.

The future trend for per capita annual electric energy consumption and peak demand can be held flat with savings achieved from DSM programs funded by the current level of the Public Goods Charge surcharge. An approximate doubling of DSM funding can cause a downward turn in the future trends for per capita electric energy and peak demand to 3 percent lower per person in 2013. Natural gas DSM programs funded by the current level of the PGC surcharge are expected to steadily reduce per capita natural gas consumption over the next decade. Additional funding for natural gas DSM programs could reduce per capita natural gas consumption even more.

Between 1990 and 2001, there was little change in the electricity system's overall efficiency. But, with the addition of about 9,300 MW of very efficient gas-fired generation in the last few years, the average has begun to drop from 8,800 Btu/kWh in 2001 towards a forecasted 8,200 Btu/kWh in 2004. Adding the renewables called for in the Renewable Portfolio Standard will improve the system's efficiency further.

## Retail Rates

Prices paid by consumers are projected to drop between 2003 and 2007, with the biggest decreases coming in the commercial and industrial sectors.

California's electricity consumers currently face considerably higher rates than consumers in other Western states. Residential, commercial, and industrial consumers currently pay as much as 53, 110 and 117 percent more in electricity rates in California than similar consumers in other Western states. Although this trend will likely decline in 2004, rates could still be 37, 58 and 47 percent higher for California's residential, commercial, and industrial users.

Residential consumers in California use much less electricity than their counterparts in other western states. Consequently, electricity bills for California's residential consumers are comparable to bills for similar consumers in other states even though their rates are 53 percent higher. Next year, a residential consumer in California will pay lower electricity bills than his counterpart in other states.

California's commercial consumers, on the other hand, pay more than double in rates and bills than similar consumers in other states. Although the trend declines next year, the burden for commercial customers remains high. California industrial consumers fare relatively better than commercial customers. Current electricity bills for California' industrial customers are approximately 67 percent higher than customers of other Western states. These bills could decline to be only 13 percent higher next year.

## Environmental Performance

All parts of the state's electrical generation and transmission system affect the natural environment and human communities. While there is good news on air emissions from natural gas-fired power plants due to declining emission rates, there continue to be serious ongoing impacts to water supplies, water quality and aquatic habitats from the current fleet of natural gas, nuclear and hydro power plants. Impacts to terrestrial ecosystems are well controlled for new power plant cases under Energy Commission jurisdiction, but impacts caused by extant and new transmission lines, natural gas pipelines and non-jurisdictional projects are not as well understood and long-term impacts remain a concern and require further investigation.

## Air Quality and Global Climate Change

For many years, air quality has been the focus of environmental attention for the power supply system. Due to air quality regulations and new technologies, the system is quite clean and on a positive trajectory towards further reductions in most areas of the state. California's reliance on in-state generation from natural gas, the cleanest of the available fossil fuels, benefits the state's air quality. Statewide, combustion-fired electric generation comprises 3 percent of the state's average daily inventories of $NO_x$, 0.47 percent of PM10 and 16 percent of the $CO_2$ inventory. Between 1996 and 2002, the generation emissions and emission percentages stayed relatively flat.
The older combined cycles have been cleaned up. Implementation of the $NO_x$ emissions control retrofit rules for utility boilers over the last decade has resulted in 80 to 90 percent reductions in $NO_x$ emission rates per MWh from these facilities. Over 85 percent of California combustion-fired generation uses some form of $NO_x$ emission controls. Nearly 21,000 MW, or 60 percent, use selective catalytic reduction for $NO_x$ emission control.

While emissions from power plants in California have improved with cleaner new technologies and tougher air quality rules, air quality levels continue to be poor. Further reductions will be needed from all sectors, including the power system,. throughout the state. Improvements are most likely to come from technological advances in emissions control, efficiency improvements and by decreasing reliance on combustion-fired generation through reduced demand or increased use of non-fired electricity sources. The Air Resources Board is investigating whether additional controls on combustion turbines are warranted. These rules will result in retrofit for some units and retirement for others. Agency coordination and research will be critical components to timely and cost-effective advances.

Reductions in residual air emissions (those emissions permitted to occur by environmental regulators) or conservation of natural resources used in energy production and consumption may come from a wide variety of measures. They include:

- Deploying cost-effective energy efficiency measures, which can avoid an environmental effect);
- Conducting energy research that may result in developing beneficial technological advances in energy use, conversion, production or transmission through continuing energy research;
- Decreasing reliance on combustion-fired generation through reduced consumer demands (especially peak); and
- Increasing use of renewable or more efficient electricity sources.

These actions will also reduce greenhouse gas emissions. California's global climate change strategy must deal with the near-term consequences of existing levels of greenhouse gases while we embark on a path to reduce future impacts.

## Water, Biology, and Other Environmental Issues

The impacts on water supply, water quality, and biological resources from new and existing generating facilities are also important elements of the power system's impact on the human and natural environment. Since most of these impacts are localized, for new facilities they can be mitigated in siting cases. Mitigation is an integral part of the cost of new supply, just as much as the cost of a new pipeline or transmission connector.

Power plants use a very small portion of the overall water supply, but like air quality, the impact can be significant in strained resource basins. In new or repowered thermal generation, alternatives to fresh water cooling need to be investigated for local impacts and cost-effectiveness. These impacts include both water use and water quality impacts on surface water bodies, groundwater and land from waste water discharge. For hydroelectric facilities, the primary impacts are on stream flow, water temperature, dissolved oxygen, water management and fish passage. Improvements need to be investigated as part of a balanced relicensing process at FERC.

The biological impacts of new power plants are mitigated as part of the licensing process and can be minimized by building facilities on previously disturbed lands. Serious impacts to aquatic ecosystems on the ocean and in sensitive estuaries are continuing at 21 power plant sites where once-through cooling systems use hundreds of millions of gallons of sea water each day. Opportunities to reduce or mitigate these impacts need to be evaluated in individual repowering cases. Pending federal regulations under the Clean Water Act for these cooling systems may provide further opportunities to mitigate impacts from existing facilities. The two primary areas of emerging concern are habitat disruption from transmission lines and facilities with large land areas such as transmission lines, gas pipelines and wind farms.

Land use, socioeconomic impacts and environmental justice are more closely tied to urbanized areas. In rapidly growing urban areas, energy infrastructure development and repowering often occurs very close to sensitive community resources such as new residential areas, schools, and recreation areas. These local quality of life issues must be addressed.

# Chapter 6: Integrated Electricity and Natural Gas Risks

California’s electricity and natural gas markets are closely inter-related. The dominant new sources of electrical power are combustion turbines and combined cycle plants fueled by natural gas. In the past decade, efficiency improvements in new gas-fired combined cycle power plants made this technology the most attractive option in terms of overall cost, load-following flexibility and ease of meeting emissions requirements.

Electricity generation demand for natural gas is driving the growth in natural gas demand throughout the United States and in California. Consequently, decisions about building additional natural gas storage, gas pipeline capacity, or an LNG terminal somewhere on the West Coast will affect what consumers pay for electricity. Conversely, development of renewable generation and electricity demand reductions can influence the demand for and price of natural gas. These common markets mean that uncertainties and risks are also linked.

California's fundamental energy problem stems from the short-term inflexibility of both energy supplies and demand. This constrains the energy market's ability to respond quickly to adverse shocks to the system. These shocks are not precisely predictable or knowable. They can only be forecasted in a probabilistic sense. These risk factors, however, can be subjected to better identification, assessment and analysis. More rigorous and robust analytical work requires reliable data inputs that can only be provided by greater transparency of market transactions, better monitoring, and improved reporting requirements.

## Natural Gas Supply and Availability Risks

In both the near-term and the long-term, supplies of natural gas will be more costly than the ten-year historic average in the 1990s. The dynamic, competitive natural gas markets will continue to exhibit variation in price over time, primarily in response to supply, demand, and regulatory factors. There is always a risk of unpredictable price volatility, though a repeat of the past three years is not expected.

For natural gas, one challenge is to determine how the infrastructure should be designed to avoid involuntary curtailment of any customer. The problem of how much to store natural gas is compounded by the market design issue of who should store, and who should have the obligation.

Declining output from several producing basins in the "lower 48" states is a long-term concern. There are new supply options within North America, and some additional gas can be gathered within California's borders. Internationally, liquefied natural gas is becoming an option as it becomes cost-effective to cool, move and re-gasify abundant but remote natural gas to load centers. LNG technology, with numerous economic and technological uncertainties and risks, has the promise to shift natural gas from a continent-wide market to a world-wide commodity market. Developing shipping access to natural gas producing basins throughout the Pacific and Indian oceans has the potential for significantly enhancing system reliability, price stability, and environmental performance.

## Resource Adequacy Concerns

The state is re-establishing requirements on utilities and energy service providers to ensure that they have procured enough resources to meet their loads. This, coupled with a revitalized market design administered by CA ISO and municipal utility control areas, will stabilize the entry and exit of cost-effective resources. For the three major IOUs, the CPUC is formulating a resource adequacy requirement that may also include a planning reserve margin for direct access load in their service territories. Resource adequacy for individual municipal utilities is being addressed by their elected governing boards. While a clear path has been developed for investor-owned utilities and municipal utilities, it is not yet clear whether the CPUC can enforce requirements for direct access providers.

## Credit and Finance Concerns

While the major IOUs are returning to more creditworthy status, financial difficulties and uncertainties continue to affect merchant plant builders. Wholesale electricity prices, in both the bilateral contract and open spot markets, are expected to remain flat or depressed through 2004. The major risk for reliability and price stability, for 2007 and beyond, is that markets will not send price signals to creditworthy builders by 2005 in time to build new capacity where it is needed. Building new transmission to serve local and regional capacity deficits is not a short-term option, because these projects require as much as 10 years.

## Hydro Risk Exposure

Hydroelectricity can provide as little as 12 percent to as much as 45 percent of California's annual electrical energy. A dry year is a risk every year, a statistical probability. But its likelihood for any one year becomes known just three months before the peak demand season—too late to secure alternative supplies. The "swing fuel" is natural gas. In a dry year, gas-fired facilities must be available to provide both energy and capacity to meet peak summer demand. When water is abundant, hydroelectricity provides an important source of energy and ancillary services. Hydro is "clean", without emissions at the power plants, and with very low fixed and variable O&M costs. Many hydro facilities are multi-purpose; providing flood control, water supply, recreation, and other benefits.

On the debit ledger, impounding and diverting structures that include hydro turbines have significantly altered most watersheds. This includes changes to the hydrograph, diminished bedload transport, and reduced biological carrying capacity of native species. The negative effects of dams with generating facilities are in addition to decades of cumulative effects from other sources, including mining, forestry, farming, fishing, water development, and habitat conversion. As a result of these developments, the risk of extinctions has increased for several populations, as noted in the ***2003 Environmental Performance Report*** (EPR). The challenge here is to identify operational and structural changes to federally-licensed facilities as they come up for renewal, changes that could appreciably benefit anadromous fish, for example, without appreciably raising ratepayer costs.

## Fuel Diversity Benefits

Flexibility of energy supply can be increased by developing a diverse mix of fuel sources and generation technologies, and by increasing the efficiency with which energy is used. Even with their much improved efficiency, the share of generation that is gas-fired is expected to increase. Fuel diversity and efficiency public interest strategies can yield substantial benefits to the public.

# Chapter 2: Electricity and Natural Gas Demand Trends Assessment

Reliable assessments of the amount, location and timing of demand growth are essential to system operators and policy makers to assess future infrastructure needs and evaluate resource options. This chapter presents the electricity and natural gas demand forecasts and scenarios prepared by the Energy Commission staff and discusses major uncertainties of those forecasts. More detail on the demand forecast methods and results are presented in Attachment 1, ***California Energy Demand 2003 – 2013 Forecast***, P100-03-002.

## California Electricity Demand: Recent Trends and Drivers

While California has more than half (55 percent) of the population in the Western U.S., we use only about forty percent of the electricity. In California, improvements in how efficiently we use electricity have largely offset growth, so that per capita use has grown only very slowly. As **Figure 2-1** shows, since the initiation of energy efficiency standards and programs in the mid-1970s, per capita use has been essentially constant, while U.S. and western use has increased. The shaded bars show the effect of economic conditions on usage. Since 1976, per capita use declined on average by two percent during recessions (the shaded bars in **Figure 2-1**), while in non-recession years use typically increased by one half of one percent. Only a small fraction of this variation is explained by weather. In the baseline demand forecast, discussed later in this chapter, this trend of relatively constant use per capita is projected to continue.

**Figure 2-2** shows key drivers for the three largest energy-using sectors, residential, commercial and industrial. While population growth, which drives residential energy growth, has been relatively stable, employment growth is more cyclical. In the late 1990s, commercial employment grew almost twice as fast as population (2.8 percent versus 1.4 percent). The growth in the commercial sector, much if it in business, computer, and financial services, increased demand for and use of office space. This rapid growth in the commercial sector is forecasted to continue, with three million new jobs created by 2013.

By contrast, manufacturing employment has still never returned to the two million jobs in place before the 1990 recession, although the technology boom turned the job losses of the early 1990s to moderate growth. As with the U.S. in general, manufacturing has been shifting abroad. Industrial employment is forecasted to grow at 0.7 percent over the next decade. The value of products shipped grows at less than 3 percent annually over the next ten years, compared to over 5 percent in the 1990s. Within the state, employment and population are expected to grow fastest in the Sacramento and San Diego areas.

**Figure 2-1**
**Total Electricity Use**
**KWh per Capita, 1960-2001**

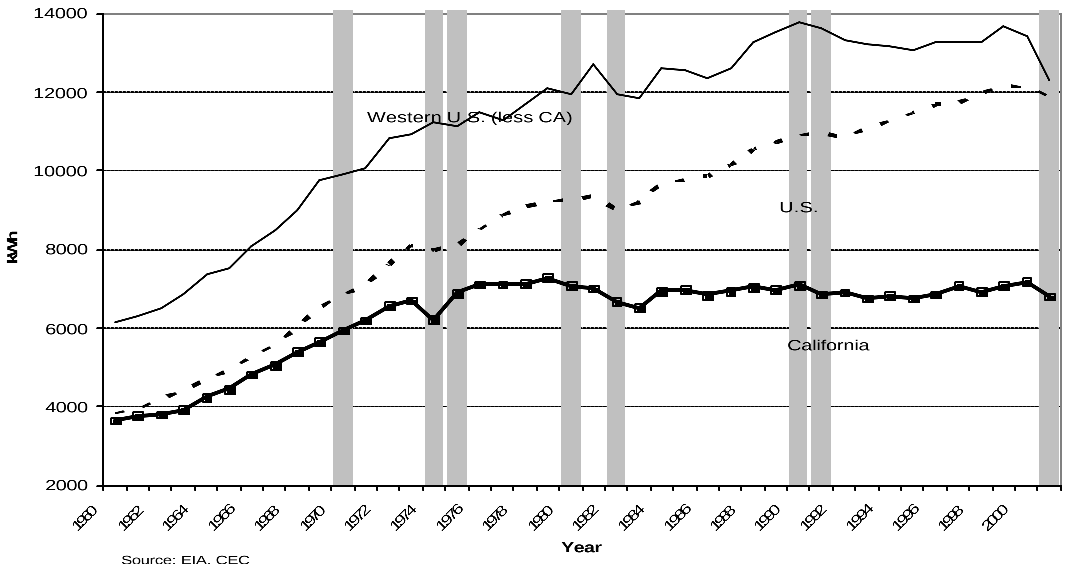
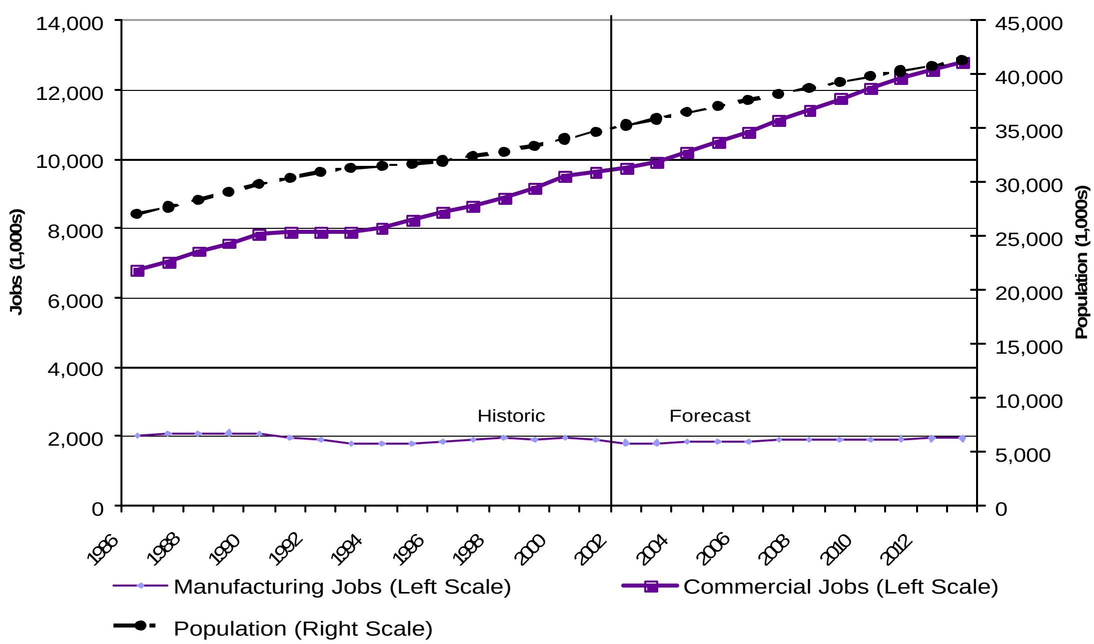



**Figure 2-2**
**California Population and Employment Growth**




While a growing population and economy are the fundamental drivers of energy demand, how much demand grows is also affected by the types of businesses that are growing, building and energy efficiency standards and programs, energy prices, and customer behavior. **Figure 2-3** illustrates usage trends for each of the major customer sectors, indexed to 1990. In the residential sector, average electricity use per household has increased one-half percent per year, reflecting higher incomes, larger homes, more homes with air conditioning, and home electronics. This increase in use per household explains only twenty percent of the 1.9 percent per year growth in the residential sector over the last two decades; growth in the number of households explains the rest.

In the commercial sector, businesses have increased electricity use per square foot. Three-fourths of commercial demand growth is due to business expansion – more floor space used by businesses – and one-fourth of growth reflects greater per unit energy use. In the industrial sector, improved productivity has led to greater electricity use per employee; even while employment was stagnant, the contribution of the manufacturing sector to gross state product grew twice as fast as the commercial sector.

**Figure 2-3**
**Electricity Utilization Rates by Sector**
**1990=100**

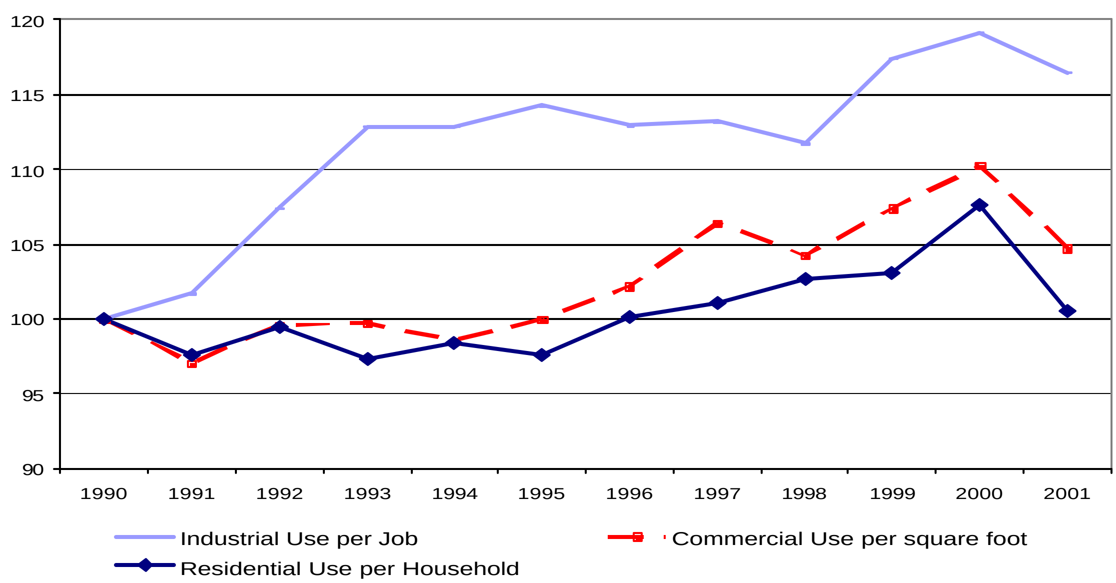
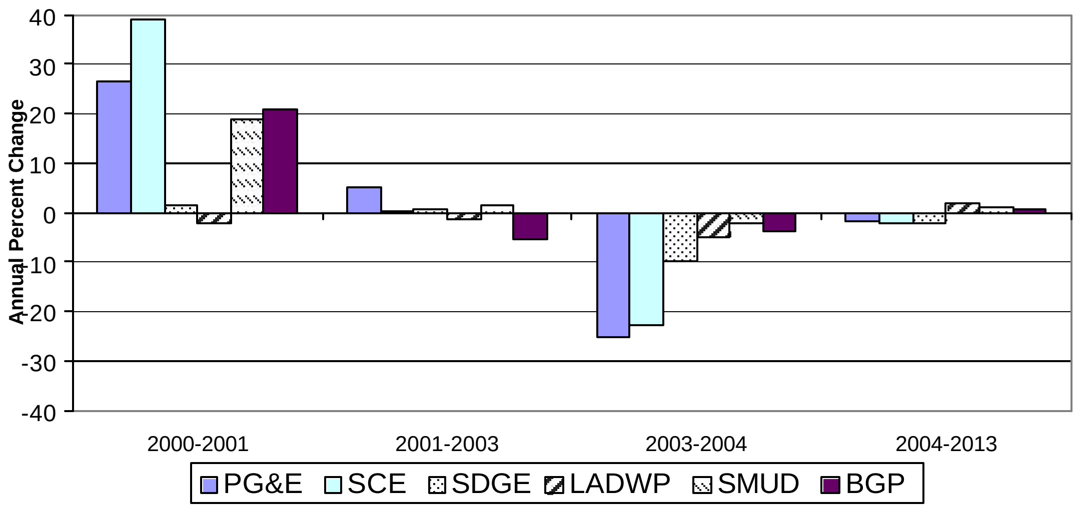



**Figure 2-3** also shows the effect of the 2001 energy crisis by sector: usage per household declined by 6.5 percent, commercial by 5 percent, and industrial by 2.2 percent. While these measures are imprecise indicators of utilization, they are roughly consistent with the Energy Commission's analysis of CA ISO data which estimated that weather- and economic-adjusted demand dropped by 6.5 percent in 2001. Most, if not all, of the decline in the industrial sector can be explained as a response to weak economic conditions and higher electricity rates. The residential and commercial decline reflects both investment in energy efficiency and behavioral changes. In the forecast, these usage rates return to an increasing trend.

Electricity rates influence how much electricity businesses and homes use. Rates, shown in **Figure 2-4,** are projected to stay relatively stable through 2003, but as bonds are repaid in 2004 rates are expected to drop from 20 to 25 percent for the three largest utilities.

**Figure 2-4**
**Percentage Change in System Average Electricity Rates**
**(2001 $)**




# Electricity Demand Futures

## The Baseline Electricity Demand Forecast

**Tables 2-1** and **2-2** show the annual electricity consumption and peak demand forecasts for selected years by utility. These data, both historical and forecast, include the impacts of energy efficiency programs, including building and appliance standards and utility energy efficiency programs. While the robust growth in income and employment of the late 1990s through 2000 is not expected to return, moderate economic growth is forecasted to resume in 2004. This, combined with retail electricity rate cuts as bonds are paid off, contributes to demand growth averaging 2.2 percent for 2004 and 2005. For the rest of the forecast period, consumption growth slows to an average of 1.4 percent, as retail rates and economic trends stabilize and the benefits of energy efficiency programs and building standards increase. Peak demand grows by more than 1,000 MW per year for the next five years. For the rest of the forecast, peak growth slows to about 700 MW per year.

**Table 2-1**
**Noncoincident System Peak Demand by Utility (MW)**

| Year | PG&E | SMUD | SCE | LADWP | SDG&E | BGP | OTHER | DWR | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1990 | 17,250 | 2,195 | 17,647 | 5,312 | 2,973 | 812 | 801 | 241 | 47,231 |
| 2000 | 20,628 | 2,688 | 19,757 | 5,344 | 3,476 | 825 | 1,023 | 250 | 53,991 |
| 2001 | 19,413 | 2,485 | 17,890 | 4,805 | 3,147 | 729 | 1,024 | 131 | 49,625 |
| 2003 | 20,145 | 2,657 | 19,118 | 5,372 | 3,806 | 864 | 1,049 | 341 | 53,351 |
| 2006 | 21,477 | 2,785 | 20,629 | 5,533 | 4,065 | 887 | 1,132 | 341 | 56,849 |
| 2008 | 22,206 | 2,861 | 21,211 | 5,588 | 4,223 | 888 | 1,172 | 341 | 58,491 |
| 2013 | 23,585 | 3,055 | 22,558 | 5,731 | 4,530 | 894 | 1,354 | 341 | 62,048 |
| **Annual Growth Rates (%)** | | | | | | | | | |
| 1990-2000 | 1.8 | 2.0 | 1.1 | 0.1 | 1.6 | 0.2 | 2.5 | 0.4 | 1.3 |
| 2000-2003 | -0.8 | -0.4 | -1.1 | 0.2 | 3.1 | 1.6 | 0.8 | 10.9 | -0.4 |
| 2003-2008 | 2.0 | 1.5 | 2.1 | 0.8 | 2.1 | 0.6 | 2.2 | 0.0 | 1.9 |
| 2008-2013 | 1.2 | 1.3 | 1.2 | 0.5 | 1.4 | 0.1 | 2.9 | 0.0 | 1.2 |
| 2003-2013 | 1.6 | 1.4 | 1.7 | 0.6 | 1.8 | 0.3 | 2.6 | 0.0 | 1.5 |

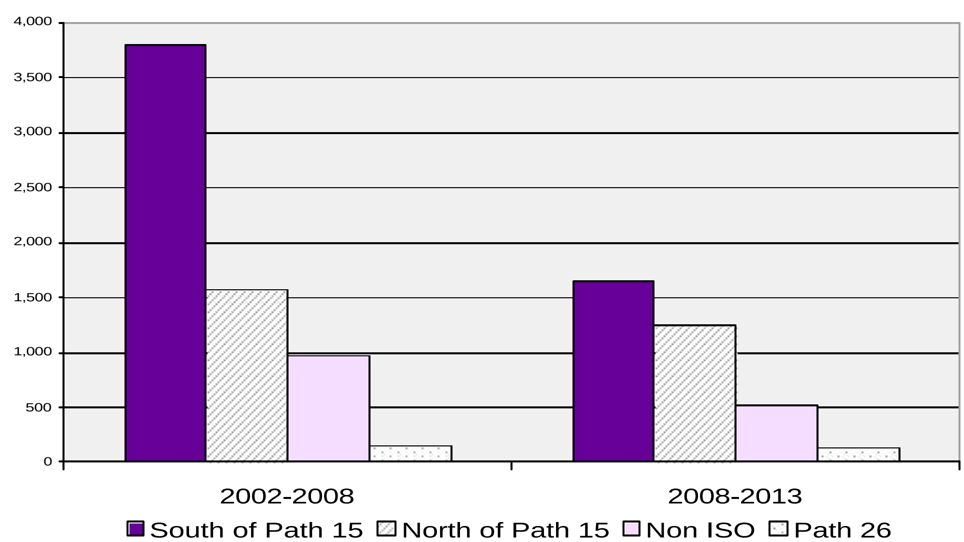
**Table 2-2**
**Electricity Consumption by Utility Planning Area (GWh)**

| Year | PG&E | SMUD | SCE | LADWP | SDG&E | BGP | OTH | DWR | TOTAL |
|---|---|---|---|---|---|---|---|---|---|
| 1990 | 86,806 | 8,358 | 81,673 | 21,971 | 14,798 | 2,951 | 3,310 | 8,171 | 228,038 |
| 2000 | 101,980 | 9,491 | 96,496 | 23,803 | 18,791 | 3,320 | 4,227 | 5,490 | 263,599 |
| 2001 | 98,748 | 9,334 | 90,506 | 23,265 | 17,822 | 3,275 | 4,230 | 6,349 | 253,528 |
| 2003 | 98,597 | 9,563 | 90,419 | 23,703 | 18,663 | 3,380 | 4,262 | 7,889 | 256,476 |
| 2006 | 105,101 | 10,060 | 97,637 | 24,570 | 19,988 | 3,504 | 4,580 | 7,889 | 273,329 |
| 2008 | 108,699 | 10,388 | 100,745 | 24,935 | 20,847 | 3,530 | 4,740 | 7,889 | 281,773 |
| 2013 | 115,507 | 11,172 | 107,654 | 25,839 | 22,518 | 3,592 | 5,415 | 7,889 | 299,586 |
| **Annual Growth Rates (%)** | | | | | | | | | |
| 1990-2000 | 1.6 | 1.3 | 1.7 | 0.8 | 2.4 | 1.2 | 2.5 | -3.9 | 1.5 |
| 2000-2003 | -1.1 | 0.3 | -2.1 | -0.1 | -0.2 | 0.6 | 0.3 | 12.8 | -0.9 |
| 2003-2008 | 2.0 | 1.7 | 2.2 | 1.0 | 2.2 | 0.9 | 2.2 | 0.0 | 1.9 |
| 2008-2013 | 1.2 | 1.5 | 1.3 | 0.7 | 1.6 | 0.4 | 2.7 | 0.0 | 1.2 |
| 2003-2013 | 1.6 | 1.6 | 1.8 | 0.9 | 1.9 | 0.6 | 2.4 | 0.0 | 1.6 |

## Peak Demand by Transmission Zone

To anticipate infrastructure needs and manage congestion, system operators need to know where growth is likely to occur. Congestion occurs on the grid when there is not enough transmission capacity to accommodate load, generation, or interchange requirements. The CA ISO, which comprises about 86 percent of California demand, uses three zones to manage congestion: North of Path 15, South of Path 15 and Path 26. North of Path 15 is largely Northern California. SCE, SDG&E, and other areas in Southern California constitute the South of Path 15 zone. Path 26 is made up of the southern portion of the PG&E system. **Figure 2-5** shows growth in peak demand by zone. Demand is expected to grow fastest in the South of Path 15 area, by 3800 MW (seventeen percent) by 2008.

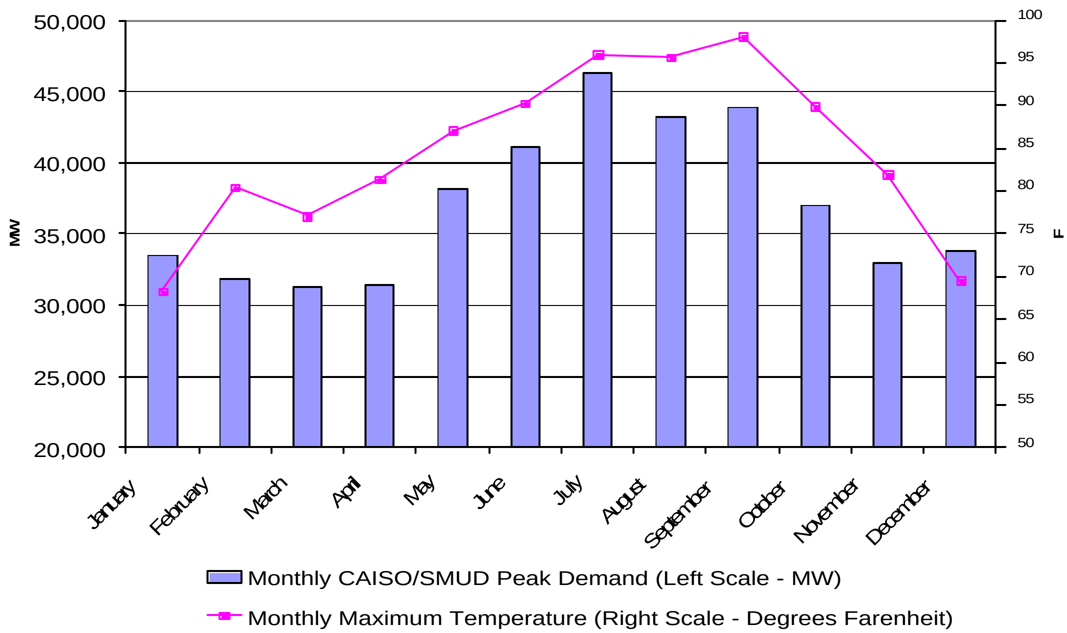
**Figure 2-5**
**Increase in Peak Demand by Transmission Zone (MW)**




## Peak Demand and Weather

While annual energy consumption is not as weather sensitive, the peak load that must be served in a given year or month varies greatly with temperature. **Figure 2-6** shows 2002 monthly peak demands for the CA ISO and SMUD areas combined, and the maximum statewide average temperature for each month. The peak for 2002 was on Wednesday, July 10 when the average temperature (weighted by distribution of air conditioning load) exceeded 96 F$^{o}$. In this case, the peak did not fall on the hottest day of the year, September 2, because that was a Monday holiday.

**Figure 2-6**
**ISO/SMUD 2002 Monthly Peak Demand and Maximum Temperatures**




To account for the effect of temperature on demand, the Energy Commission develops demand forecasts for varying degrees of hotter than average temperatures. The baseline peak demand forecast assumes average temperatures—temperatures that are expected to occur, on average, in one out of every two years (one-in-two). To account for warmer than average temperatures, temperature sensitivities for 1-in-five, -ten, and -forty weather conditions are applied to the baseline peak demand forecast. The resulting peak demand weather scenarios are shown in **Figure 2-7**. The one-in-five scenario, which has a twenty percent chance of occurring in any year, increases peak demand by 3.6 percent. In the one-in-ten scenario demand is increased by 6.1 percent, while in the one-in-forty scenario demand is increased by 8.5 percent.

The distribution of load over the course of the year is an important characteristic of demand. System operators must plan for sufficient capacity to meet peak demand, but in off-peak hours only some fraction of that capacity will be used. The load factor, defined as average demand relative to peak demand, measures the extent to which capacity is being used. A load factor of 100 percent would mean demand is constant in all hours, so there need be no unused capacity in any hour. Conversely, a low load factor means much of the resources needed to meet demand in the peak hour sit idle in other hours. While the increasing proportion of homes and businesses with air conditioning has caused load factors to trend down, load factors vary year to year depending on weather, as shown in **Figure 2-8**. For example, 1998 was overall a very cool year except for a brief hot spell, so average hourly demand was much less than the peak hour, resulting in a load factor of only 52.7 percent. In 2001, the load factor was up to 60 percent as businesses and consumers chose to use less air conditioning in response to the energy crisis.

**Figure 2-7**
**Coincident Peak Demand (MW)**
**Normal and Hot Weather Scenarios**

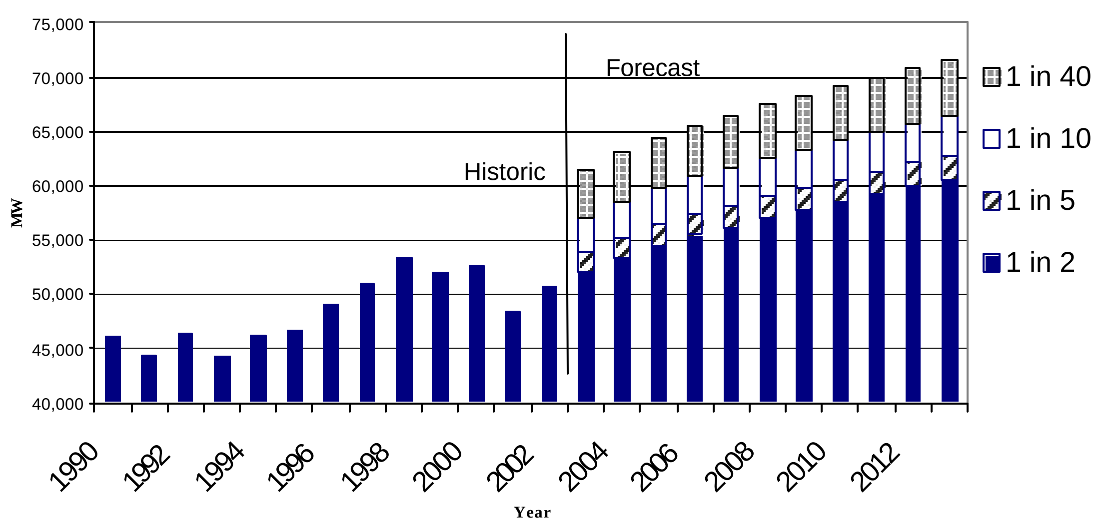
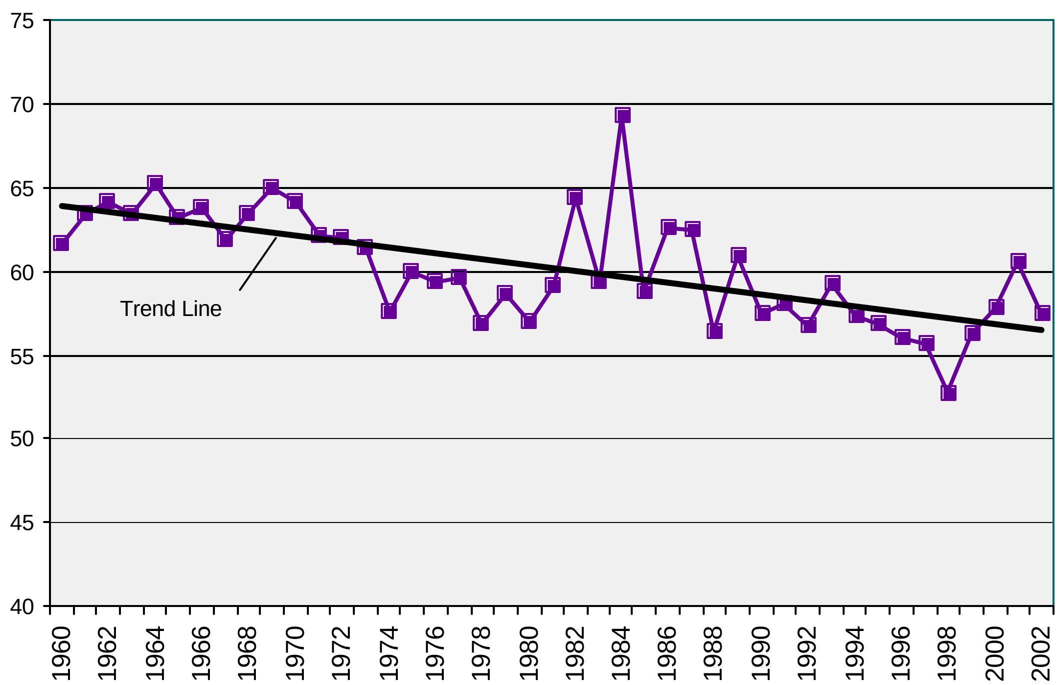



**Figure 2-8**
**California Annual Load Factors (%)**



Electricity use varies widely over the time of day and time of year. In a typical day, use increases 60 percent from the midnight low to the afternoon high. On a hot summer day, this swing is 85- 90 percent. To supply this variable load requires a generation system that is extremely flexible.

Demand response or load management programs can increase the load factor by shifting demand away from peak hours. On the other hand, while energy efficiency programs or building standards may contribute to a lower absolute peak. They may also increase the load factor - they reduce off-peak demand more than they reduce on-peak demand. In the Energy Commission's peak demand forecast, load factors are projected to remain at about 57 percent.

## A Range of Demand Futures

While Energy Commission demand forecasts have historically been reasonably accurate, they have tended to err on the high side, but that may be less likely to be true of this forecast. Major sources of forecast error are uncertainty in the economic forecast, price forecast, and usually conservative assumptions about uncertain trends. For example, the ***California Energy Demand 2002-2012*** (***CED 2002***) forecast was 8 percent higher in 2008, reflecting the more optimistic outlook on the economy at that time. Because current economic forecasts have greatly reduced expectations, this forecast may be less likely to overestimate future demand.

Also, this forecast assumes utility energy efficiency programs will be funded at current levels through 2011. This is a less conservative assumption than past Energy Commission practice, when typically not more than three years of future funding were assumed, as approved in the CPUC ratemaking cycle. In this forecast, because the state legislature has approved funding for utility energy efficiency programs through 2011, those future years of funding are considered committed. While current state policy suggests this is a reasonable assumption, it is more uncertain whether the assumed savings in the latter part of the forecast will be achieved.

To quantify the potential impact on demand of unanticipated economic or energy efficiency trends, the Energy Commission developed several scenarios to support evaluation of risks to infrastructure and supply adequacy.

### Economic Scenarios

The baseline forecast assumes that stronger economic growth will resume in 2004, followed by steady growth, but at a lower rate than previous recoveries. The high economic growth scenario reflects the effects of a more robust economy on energy demand. Over the last twenty years, the average annual post-recession employment growth rate has averaged about one percent higher than the growth rate assumed in the baseline employment forecast. To estimate the effects of stronger economic growth on energy demand, the employment forecast was accelerated to achieve a new forecast with an annual growth of slightly more than 1 percent higher for the years 2004-2007. Other economic drivers for the sector forecasts were also accelerated by one or two years for similar results. After 2007, the baseline forecast trend resumes. The resulting forecast is very similar to the ***CED 2002*** forecast.

Conversely, to develop a low economic growth scenario, the forecasted growth beginning in 2004 is delayed by one to two years so that growth on average is slightly more than 1 percent lower than the baseline economic forecast. **Table 2-3** summarizes key economic drivers under each scenario.

**Tables 2-3 and 2-4** summarize these scenarios and their effects on forecasted electricity demand. In the highest scenario, an increase in economic growth increases peak demand by more than 1600 MW in 2008. In the low economic growth scenario, demand is about 1700 MW lower in 2008 compared to the baseline forecast. **Table 2-5** shows the forecasts of net energy for load, which is the amount of energy including losses that must be served by the grid.

**Table 2-3**
**Summary of Demand Forecast Scenarios**

| Scenario Name | Description | Average Annual Peak Demand Growth 2004-2008 | MW Difference in 2008 |
|---|---|---|---|
| Baseline | | 1.7% | 0 |
| High Economic Growth | Economic growth 2004-2008 1 percent higher than baseline | 2.2% | 1659 |
| Low Economic Growth | Economic growth 2004-2008 1 percent lower than baseline | 1.1% | -1736 |
| High DSM | Doubling of energy efficiency spending 2004-2013 | 1.3% | -1007 |
| Low DSM | Elimination of energy efficiency spending 2004-2013 | 2.1% | 1073 |

How likely are these scenarios? Because economic outcomes are a result of interactions of many variables, we cannot easily calculate probabilities of future events based on the past. For example, while previous recessions were driven by declines in consumer spending, the recession which began in 2001 has been driven by a decline in business investment. Therefore previous post-recession periods do not provide a valid comparison for predicting future outcomes. While it is virtually certain that sometime in the next ten years we will experience a business cycle higher or lower than anticipated, under current economic conditions, these specific scenarios probably each have between 10 and 20 percent likelihood. These are not worst case scenarios, but are intended to provide a plausible range of outcomes for infrastructure assessment.

**Table 2-4**
**Statewide Demand Forecast Scenarios**
**Net Peak (MW)**

| Year | Baseline | Low Economic Growth | High Economic Growth |
|---|---|---|---|
| 2003 | 53,351 | 53,351 | 53,351 |
| 2004 | 54,639 | 54,321 | 55,178 |
| 2005 | 55,837 | 55,126 | 56,780 |
| 2006 | 56,849 | 55,724 | 58,223 |
| 2007 | 57,574 | 56,052 | 59,365 |
| 2008 | 58,491 | 56,755 | 60,150 |
| 2009 | 59,174 | 57,402 | 60,771 |
| 2010 | 59,926 | 58,147 | 61,461 |
| 2011 | 60,670 | 58,893 | 62,142 |
| 2012 | 61,447 | 59,659 | 62,931 |
| 2013 | 62,048 | 60,324 | 63,566 |

**Table 2-5**
**Statewide Demand Forecast Scenarios**
**Net Energy for Load (GWh)**

| Year | Baseline | Low Economic Growth | High Economic Growth |
|---|---|---|---|
| 2001 | 263,533 | 263,533 | 263,533 |
| 2002 | 262,189 | 262,189 | 262,189 |
| 2003 | 264,874 | 264,874 | 264,874 |
| 2004 | 271,019 | 269,452 | 273,658 |
| 2005 | 277,237 | 273,673 | 281,853 |
| 2006 | 282,786 | 277,227 | 289,598 |
| 2007 | 286,692 | 279,204 | 295,579 |
| 2008 | 291,702 | 283,304 | 300,032 |
| 2009 | 295,245 | 286,733 | 303,207 |
| 2010 | 299,222 | 290,760 | 306,890 |
| 2011 | 303,257 | 294,799 | 310,571 |
| 2012 | 307,266 | 298,769 | 314,636 |
| 2013 | 310,403 | 302,277 | 317,948 |

## Energy Efficiency Scenarios

The baseline electricity forecast reflects the assumption that current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the legislature. To estimate the effect on demand of increased investment in energy efficiency, staff used scenarios developed as part of a recent series of studies of energy efficiency savings potential in California.[1] These studies estimated the amount of cost-effective, achievable potential available statewide, and then estimated how much of that potential would be attained at alternative funding levels. These studies use Energy Commission data as the foundation of their analysis, so the results are largely consistent with the assumptions embedded in the baseline forecast.

The high demand-side management (DSM) scenario estimates the effect on demand of roughly doubling the amount of energy efficiency spending statewide beginning in 2004 and continuing through 2013. Increasing PGC spending on electricity efficiency to $572 million per year from $240 million per year (based on average spending 1996-2000), reduces demand by about 1800 MW in 2013. Eliminating all spending on energy efficiency after 2003 would increase demand in 2013 by about 1900 MW. These scenarios and their policy implications are discussed in more detail in the ***Public Interest Energy Strategies Report***.

In **Figures 2-9 and 2-10,** the DSM scenario results are shown per capita. In the high DSM scenario, per capita consumption declines by about 240 kWh per person (more than three percent) by 2013, compared to almost constant use per capita in the baseline. Without any future spending on energy efficiency programs, per capita consumption would increase by more than three percent by 2013.

**Figure 2-9**
**Statewide DSM Scenarios**
**Consumption per Capita (kWh)**

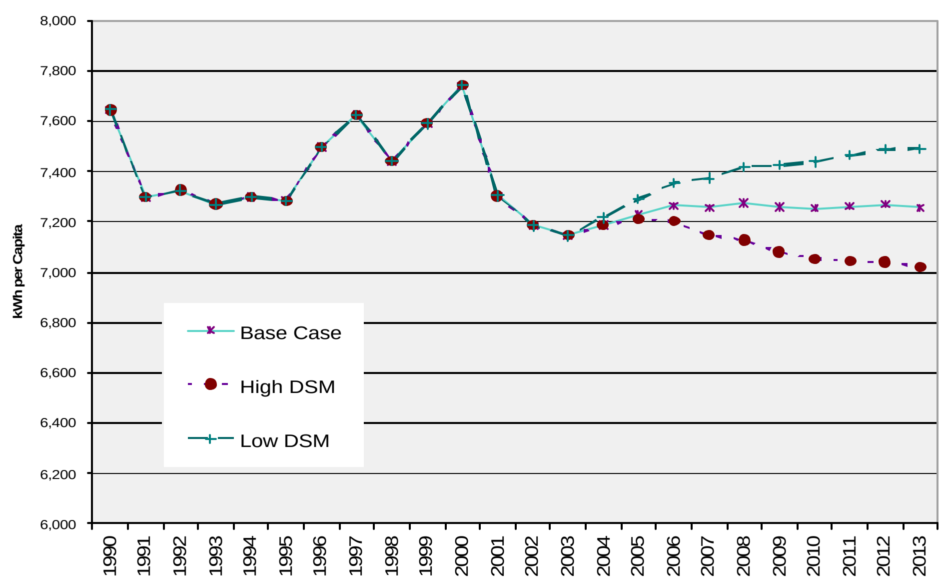
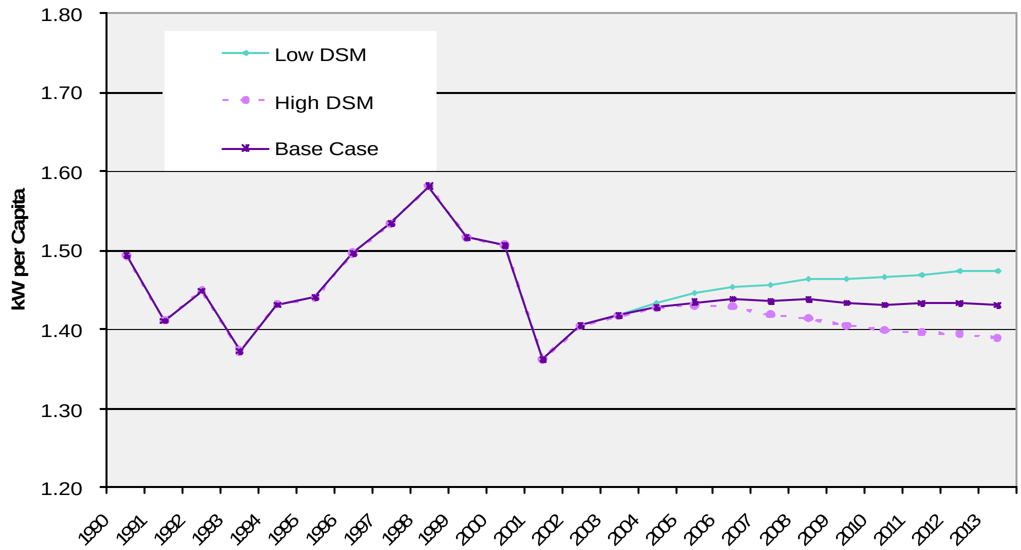


**Figure 2-10**
**Statewide Electricity DSM Scenarios**
**End Use Peak Demand per Capita (kW)**




## Other Uncertainties that May Affect the Forecast

### Rate Structures and Levels

These forecasts assume that current rate structures, in which most electricity customers are not exposed to prices that vary in response to market conditions or time of use, continue. If increasing numbers of customers are subject to dynamic pricing or other more variable rate structures, increased investment in energy efficiency and behavior changes such as load shifting could affect both peak and annual energy demand.

### Privately Supplied Energy

Electricity consumption needs that are met by self-generation or distributed generation reduce the demands on the grid. About 4 percent of the total electricity consumption reported in **Table 2-2** is served by this privately supplied energy. (Private supply is different from sales to direct access customers, which are served by the grid. About 10 percent of current and forecast annual consumption represent sales by direct access providers.)

After several years of no growth, private supply has increased by about ten percent over the last three years. This is a result of the energy crisis, changes in the regulatory environment, and higher rates, but it is not yet clear this more favorable environment for increased off-grid private supply will continue. After 2003, privately supplied load is assumed to grow at one percent per year. This conservative estimate is used because of the uncertainty of the effects of regulatory policy on the economic attractiveness of self-generation. If private supply grows faster than anticipated, the demand for energy from the grid is reduced. For example, if private supply were to grow at five percent per year, peak demand would be reduced by about 430 MW in 2008 compared to the baseline forecast.

### Effects of the Energy Crisis

The energy crisis of 2001 motivated a dramatic response from customers. While some of this was the effect of investments in energy efficiency that will persist for many years, a large portion of the response was voluntary behavior change, e.g., not running air conditioners. For 2002, the Energy Commission estimates that about one-third to one-half of this reduction in annual energy consumption remained. After dropping by more than 3,000 MW in 2001, statewide non-coincident peak increased by 2,375 MW in 2002, as the need for public response to the crisis ended. This reduction in crisis-driven conservation behavior in 2002 is accounted for in the forecast, and the forecast assumes the remaining behavioral conservation will gradually diminish. By 2005, commercial use per square foot is expected to return to the levels of the late 1990s. However, residential consumption per household does not return to those levels until 2007. If this conservation behavior diminishes more rapidly, residential peak demand could grow more quickly than forecast.

## California End-User Natural Gas Demand: Recent Trends and Drivers

In the largest natural gas-using sector, residential use per household, shown in **Figure 2-11**, has generally declined reflecting savings from building and appliance standards. The exceptions to this trend, such as 1998 and 1999, were years with much cooler temperatures, causing increases in demand for heating. The commercial sector shows a similar trend, although with utilization declining more during periods of economic weakness. In manufacturing, increasing energy intensity in the 1990s reflects in part a shift away from petroleum-based fuels to cleaner-burning natural gas. With that transition complete, manufacturing usage is relatively flat.

### Natural Gas Prices

The retail price forecast used for this forecast is shown in **Figure 2-12.** After forty percent increases during the energy crisis in 2000 and 2001 and then falling back to 1999 levels, prices are expected to rise at less than two percent annually on average.

**Figure 2-11**
**Natural Gas Utilization Rates by Sector**
**1990=100**

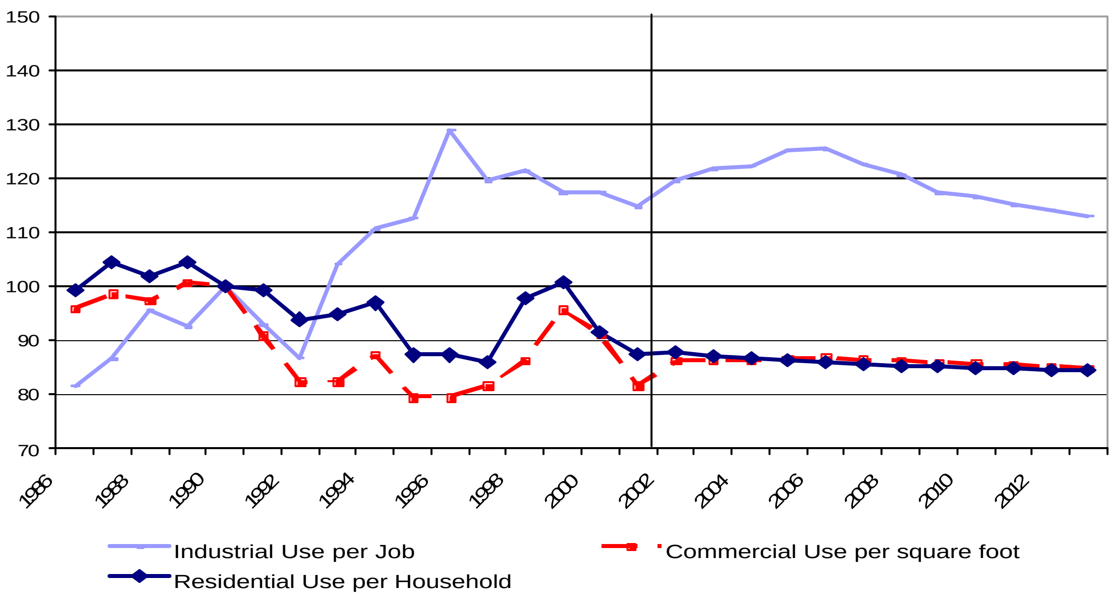
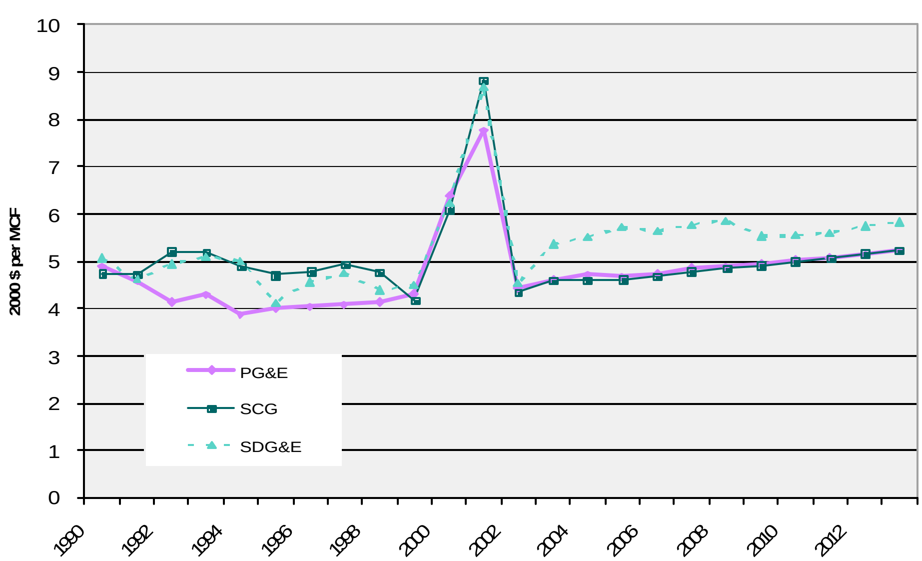



**Figure 2-12**
**System Average End User Natural Gas Prices**
**$2000 per MCF**



# Natural Gas Demand Futures

## Baseline Natural Gas Demand Forecast

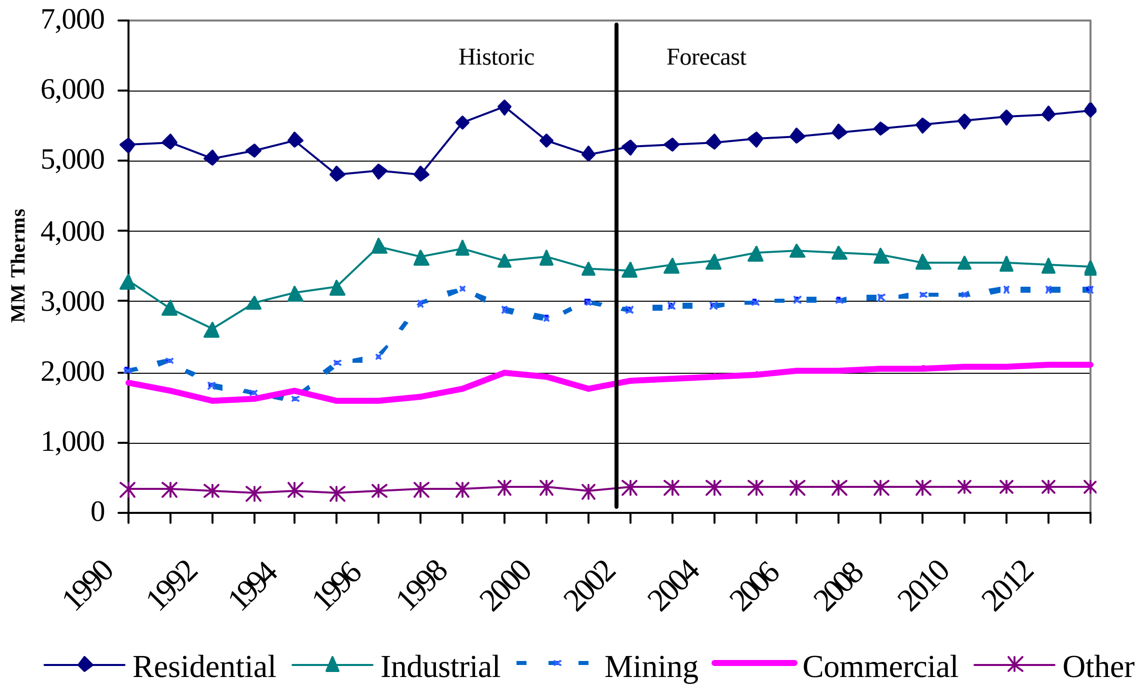
**Table 2-7** shows historic and forecast natural gas consumption for each California natural gas utility planning area—PG&E, SDG&E, Southern California Gas (SCG), and Other. The data shown are for selected years and exclude natural gas used in the production of electricity, whether that gas is used by power plants or by cogeneration facilities. (Total gas demand is described in chapter 4). The natural gas demand data, both historical and forecast, include the impacts of natural gas energy efficiency programs, including building and appliance standards and utility energy efficiency programs. This forecast assumes that current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the state legislature.

After dropping more than 6.5 percent in response to the gas price spikes of 2000-2001, natural gas use is expected to increase at a rate of 0.6 percent per year over the next ten years. Demand in PG&E grows at less than a half percent per year, as a result of weak economic growth and declining demand in the industrial sector. In SDG&E, higher than average population and economic growth produce the strongest demand growth (1.3 percent). **Figure 2-13** shows statewide demand by sector. Growth is strongest in the commercial and residential sectors (averaging 1 percent and 0.9 percent per year respectively), and weakest in the industrial sector (-0.1 percent per year).

**Table 2-7**
**Natural Gas Consumption by Utility Planning Area**
**(Millions of Therms)**

| YEAR | PG&E | SCG | SDG&E | OTHER | TOTAL |
|---|---|---|---|---|---|
| 1980 | 5,911 | 7,168 | 468 | 78 | 13,625 |
| 1990 | 5,278 | 6,806 | 517 | 95 | 12,695 |
| 1999 | 5,473 | 8,347 | 617 | 132 | 14,569 |
| 2000 | 5,339 | 7,939 | 567 | 119 | 13,964 |
| 2001 | 4,964 | 7,966 | 560 | 119 | 13,609 |
| 2003 | 5,344 | 7,907 | 568 | 121 | 13,940 |
| 2006 | 5,523 | 8,232 | 596 | 124 | 14,475 |
| 2008 | 5,531 | 8,312 | 611 | 125 | 14,580 |
| 2013 | 5,545 | 8,535 | 644 | 128 | 14,852 |
| **Annual Growth Rates (%)** | | | | | |
| 1980-1990 | -1.1 | -0.5 | 1.0 | 2.0 | -0.7 |
| 1990-2000 | 0.1 | 1.6 | 0.9 | 2.3 | 1.0 |
| 2000-2003 | 0.0 | -0.1 | 0.1 | 0.5 | -0.1 |
| 2003-2008 | 0.7 | 1.0 | 1.5 | 0.8 | 0.9 |
| 2008-2013 | 0.0 | 0.5 | 1.1 | 0.4 | 0.4 |
| 2003-2013 | 0.4 | 0.8 | 1.3 | 0.6 | 0.6 |

**Figure 2-13**
**Statewide Natural Gas Consumption by Sector**
**(Millions of Therms)**



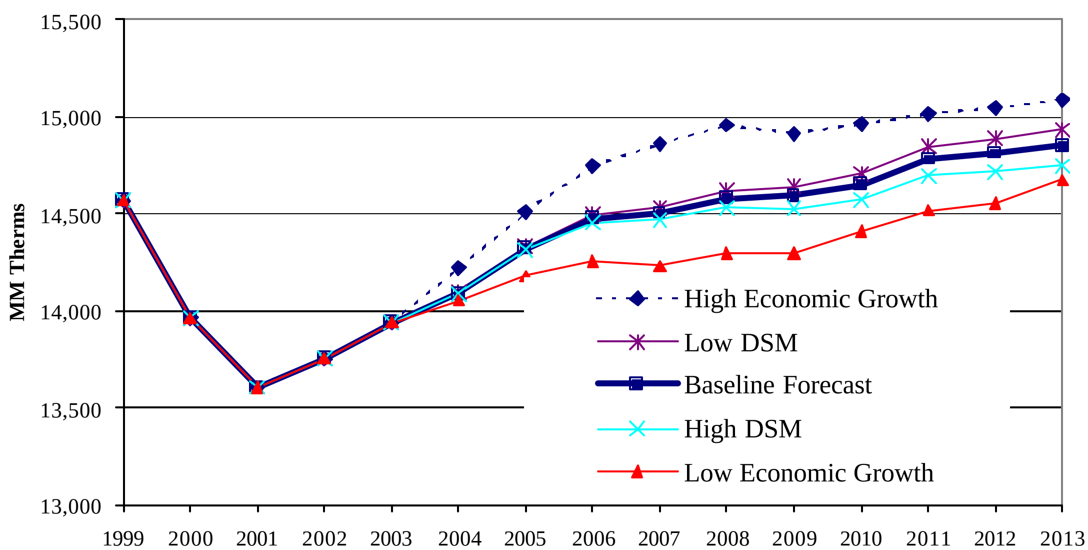

## Alternative Natural Gas Demand Futures

To quantify the potential impact on demand of unanticipated economic or energy efficiency trends, the Energy Commission developed several scenarios to support evaluation of risks to infrastructure. **Table 2-8** and **Figure 2-14** summarize these scenarios and their effects on forecasted demand. See the electricity demand section for discussion of the scenario definitions. In the highest scenario, an increase in economic growth increases the natural gas demand by 2.6 percent in 2008. In the low economic growth scenario, demand is about 2 percent lower in 2008. The demand-side management (DSM) scenarios have a much smaller effect on demand.

**Table 2-8**
**Summary of Natural Gas Demand Forecast Scenarios**

| Scenario Name | Description | Average Annual Demand Growth 2004-2008 | MM Therms Difference in 2008 |
|---|---|---|---|
| Baseline | | 0.9% | 0 |
| High Economic Growth | Economic growth 2004-2008 1 percent higher than baseline | 1.4% | 377 |
| Low Economic Growth | Economic growth 2004-2008 1 percent lower than baseline | 0.5% | -280 |
| High DSM | Doubling of energy efficiency spending 2004-2013 | 0.8% | -50 |
| Low DSM | Elimination of energy efficiency spending 2004-2013 | 1.0% | 40 |

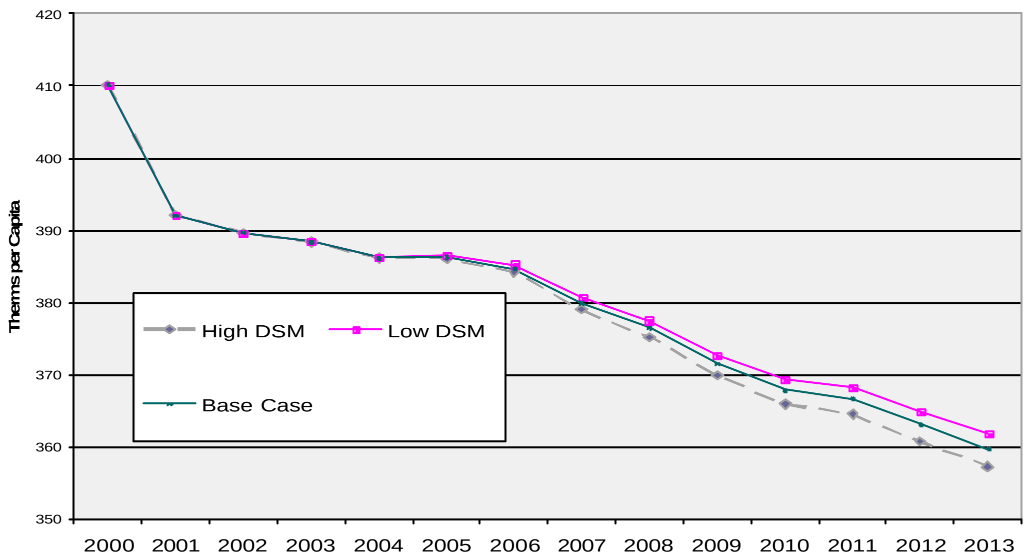
**Figure 2-14**
**Statewide Natural Gas Demand Scenarios**




The natural gas high DSM scenario estimates the effects of roughly doubling spending on energy efficiency programs for the residential and commercial sectors. Increasing spending on natural gas efficiency to $233 million per year from $102 million per year (based on average spending 1999-2000) reduces demand by about 103 million therms in 2013. No data were available on industrial energy efficiency potential, so industrial demand is unchanged in the DSM scenarios. The low DSM scenario assumes that no utility energy efficiency spending continues after 2003.

**Figure 2-15** shows the effect of the DSM scenarios on per capita natural gas demand. In the high DSM scenario, per capita consumption declines by 8 percent by 2013, compared to a 7.4 percent decrease in the baseline. Without any future spending on energy efficiency programs, per capita consumption would decrease by less than 7 percent by 2013.

**Figure 2-15**
**Statewide Natural Gas Savings by Scenario**
**Therms per Capita**



# Chapter 3: Electricity Infrastructure Assessment

This chapter begins with a brief description of how the expansion, operation, and risks of the electricity generation, electricity transmission, natural gas supply and natural gas pipeline infrastructure are integrated. Next, examples are given of how this integration leads to risk tradeoffs. Then a brief description of the state's existing electricity generation and transmission system is provided, followed by an assessment of current (2003) electricity market conditions. With that foundation laid, the chapter next assesses the near-term (2004-2006) market conditions, providing a near-term electricity supply and demand balance and a discussion of a variety of risks that need to be managed during this period.

The latter part of the chapter discusses the results of longer term (2007-2013) scenario analyses. These scenarios are focused on identifying the potential effects on the natural gas supply and transmission infrastructure of variations in key uncertainties affecting the electricity market. Collectively, these scenario assessments, together with the preceding short-term market assessments, provide the background for the discussion of long-term electricity market problems and potential policy options found in Chapters 5 and 6.

## Integration of Electricity and Natural Gas Markets and Infrastructure

California's electricity and natural gas system must supply as much power and fuel as people demand, when they demand it and where they demand it. This complex interaction among consumer habits, generation, pipelines, transmission lines, fuel sources and fuel storage facilities must be designed to achieve safe, reliable, affordable energy services. The electricity and natural gas that are delivered on demand to end users comes to them via a physical infrastructure that stretches across Western North America. In each case, the customers are connected to local distribution systems, which are in turn connected to higher volume regional transmission systems, which are supplied by a widespread network of conversion (power plant) or collection (wellhead) facilities, which depend on a variety of fuel or primary energy sources from different locations and with different characteristics.

Primary energy supplies for electric generation can be coal, uranium, geothermal heat, wind, the heat or light of the sun, biomass, landfill or agricultural digester gas, oil, or natural gas. Each of these primary energy sources of electricity has its own geographic distribution, determining which resources are economic to develop and by whom. Likewise, the primary energy sources of the natural gas delivered to end users are geographically widespread. Even if the physical nature of these different gas supplies (e.g., heat content of the gas) is somewhat similar, the techniques and costs of mining them can be very different.

Electricity cannot be stored in large quantities and is generated virtually at the instant it is demanded, with the primary energy source being consumed at that moment. Delivering power on demand to the end user at the precise voltage and frequency required by electrical appliances requires the coordinated planning, development and operation of the network of distribution wires, high voltage transmission lines, and generating plants. Reliable service is a function of this system as a whole, not any individual part. As the demand for power on the system changes from second to second, corresponding adjustments are made to the operating level of generating units across the system to precisely balance supply and demand. At times of highest power demand, usually on hot summer days, "peaking capacity" resources reserved for this situation are dispatched to maintain the system's supply and demand balance. Since natural gas is the prime fuel of these peaking power plants (i.e., baseload plants) as well as many of the power plants dispatched before and more often than the peaking plants, electricity and natural gas supply and transmission infrastructures are linked—as are the prices of the wholesale electricity and natural gas markets.

Natural gas is consumed directly by end users as a fuel in the residential, commercial, industrial sectors, and to a lesser extent in the transportation sector. Cold winter weather is a major driver of this end use demand for gas. Another major end use of natural gas is as a feedstock in the industrial sector. Increasingly, natural gas is an important fuel for the generation of electricity. The consumption of natural gas for electric generation is the largest driver of the long-term trend of increasing demand for natural gas. To complicate matters, there can be large annual variations in natural gas demand for electric generation because gas-fired generation is the system's marginal source of electricity. Generally higher temperatures and low availability of hydroelectric (or other) generation resources are made up by increased gas-fired generation. Conversely, gas-fired generation will be cut back if temperatures are milder and other generation supplies are abundant.

Delivering natural gas on demand to the end user requires the coordinated planning, development and operation of the network of distribution pipeline, high volume transmission pipeline system, gas storage facilities, and supply sources. As mentioned above, the electricity and gas infrastructures are linked by the key role of gas-fired electricity generators, whose generally upward trending but annually variable gas demand is a key factor in natural gas infrastructure issues. So, maintaining an adequate natural gas infrastructure also requires coordinating its planning, development and operations with that of gas-fired electricity generators. Unlike electricity, natural gas can be stored (in pipelines by increasing the pressure of the gas and in peaking storage facilities). This gives the natural gas system somewhat more flexibility than the electricity system in supplying peak gas demand. However, having an adequate infrastructure to meet peak gas demand is as important for the gas system as it is for the electric system to meet its peak demand.

# Risk Tradeoffs in Electricity and Natural Gas Markets

Having the electricity and natural gas infrastructure we want requires us to balance our exposure to many interrelated risks that can be condensed into energy shortage, price and environmental risks. Shortage risks include the effects of rotating electricity outages or natural gas curtailments. Price risks include exposure to high near-term or long-term power or gas costs. Environmental risks include damaging effects to air quality, water supply and quality, biological resources, climate, etc. The risks can't be eliminated. The best we can do is to manage our exposure to them--with the goal of being better off than if we hadn't attempted any risk management.

We have to expect to make tradeoffs among these risks. Tradeoffs are made by balancing costs and risk reducing benefits. We could spend billions of dollars to avoid virtually all shortage risks but, in doing so, we would create more price risk compared to the benefit expected from removing the shortage risk. Immediately shutting down all energy facilities that pose environmental risks would lead to both increased shortage and price risks that may not outweigh benefits. Investment in a precautionary risk management measure, e.g., 30 percent electricity reserves, will reap an occasional big expected benefit in the form of reduced price or outage risk. But the cost of attaining that level of reserves could outweigh the expected benefits.

There are two points in time at which risk trade-offs are made. Looking far ahead we decide now how much reserves to buy. Our expected benefits will be in the form of some combination of reduced price (of congestion) and improved reliability (deliverability). The other time frame is in the short-term when the adverse shock occurs—at this time our amount of generation is fixed. Then we face a trade-off between shortage and price. We can pay a steep price to bid all available and deliverable supplies from other parts of the West. Or we may pay less and suffer greater outages. The prior long term decision on the amount of resources to buy determines how painful a short-term trade off between price and shortage we have to face.

There are risk tradeoffs within these three broad categories of risk, as well. For example, to comply with a congressional mandate to add oxygen to gasoline to reduce air emissions, many of the nation's refiners decided to add MTBE to gasoline, a decision that was subsequently found to pose a significant threat to water quality. Similarly, substituting wind generation for gas-fired generation to reduce air quality related risks can increase biological resource risk by increasing avian mortality or habitat destruction.

These examples help to illustrate key features of useful risk assessments, which ideally should:

- Identify the most significant risk factors
- Identify how the risk factors interrelate
- Define what costs will be included in the assessment and how to include them

- Measure the magnitude of the combined interrelated risks (the probability-based costs)
- Comprehensively identify risk management options
- Measure and compare relative cost of risk management options and their performance in reducing risks (providing risk reducing benefits)
- Select risk management options that lead to lowest expected combined risk exposure

The assessments in this cycle of the ***Electricity and Natural Gas Assessment*** can not claim to meet these ideal specifications. More work remains to be done to have confidence that overall risk exposure is being managed as well as it can be.

# Existing Electricity Supply and Transmission Infrastructure

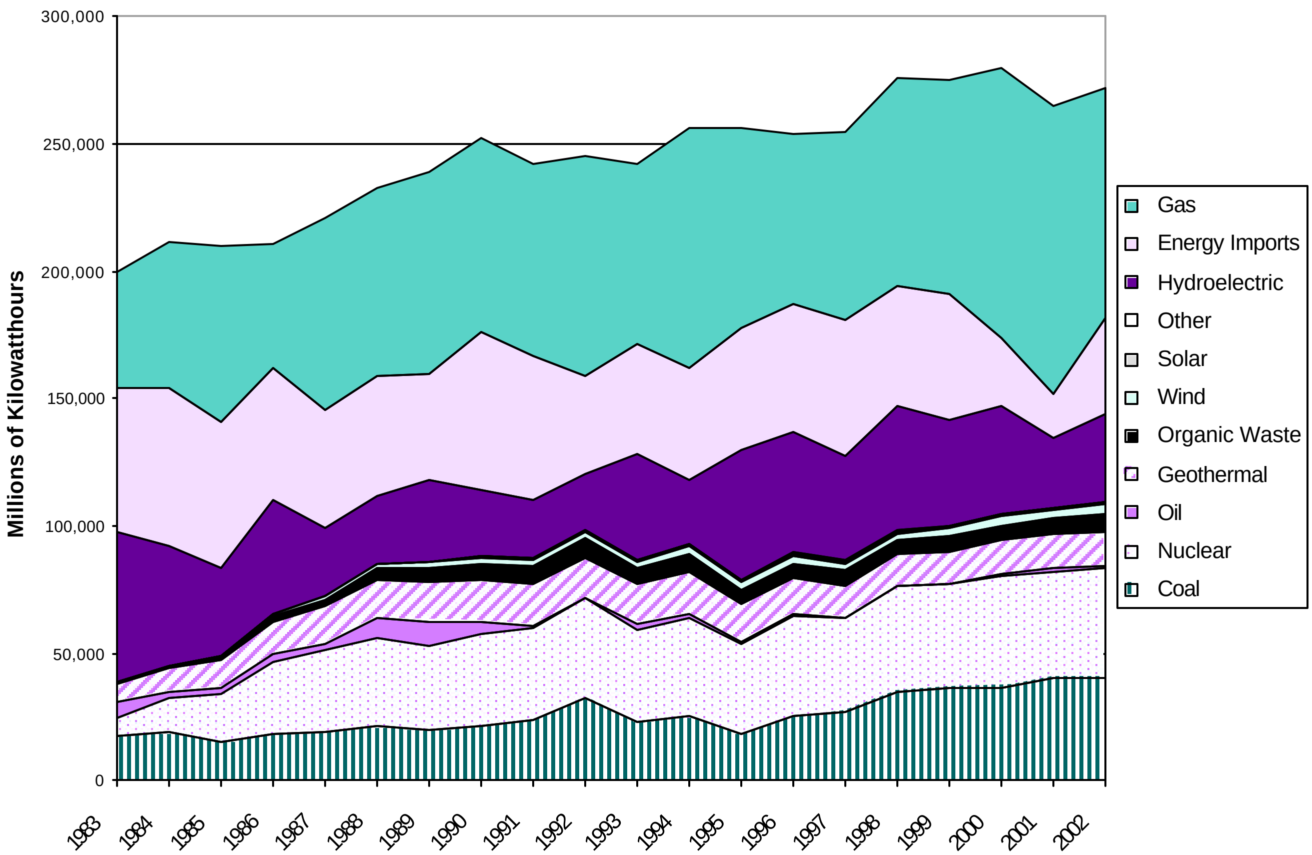
## Generation Resources

California's demand for electricity is served by a mixture of resources. Energy is provided from plants that are owned by California utilities, independent generators, and federal and state agencies. The more than 54,000 MW of capacity producing marketed energy[2] include plants using gas and oil (54 percent of capacity), hydropower (16 percent), nuclear (11 percent), coal (9 percent), and renewable energy sources (9 percent). Energy is provided from plants that are owned by California utilities (48 percent of capacity), merchant generators (35 percent), qualifying facilities (11 percent) and federal and state agencies (7 percent). California utilities own more than 6,200 MW of capacity in Arizona, Nevada, Utah and New Mexico. In addition, out-of-state utilities provide energy to California under long-term contract and through spot market sales. A detailed description of California's generation facilities is contained in the companion document: the ***2003 Environmental Performance Report*****.**

Natural gas plants have become the capacity of choice in California, as they are more efficient, more flexible to site and operate and cheaper and cleaner than many other central station options. This has resulted in an increased reliance on natural gas as a generation fuel. **Figure 3-1** shows the growth of gas-fired generation from its 25 percent share twenty years ago. Today, 35 - 40 percent of the electricity consumed in California is generated using natural gas. The figure also illustrates the variability of hydro generation in both California and in the Northwest, the latter reflected in the amount of energy imported. Combining in-state and out-of-state sources, hydropower's contribution ranges from a low of 12 percent in 2001 to a high of 45 percent in the very wet year 1983.

Much attention has been focused recently on the age and reliability of the state's gas-fired power plants. These plants have varying characteristics and provide a range of services including baseload energy, following load through its daily swings to serving as the source of peak capacity only a few times per year. Overall, the system has been getting more efficient as new units are added. Of the 54,675 MW of capacity owned by California utilities, 9,369 MW has been added since 2000. However, there is continued concern over the cost, reliability, function and emissions of the oldest power plants. **Table 3-1** shows the age distribution of power plant capacity and each age cohort's share of total 2002 energy generation.

**Figure 3-1**
**Sources of California Electrical Energy Consumption**
**1983 - 2002**




While the retirement of older plants can be anticipated during the remainder of the decade, the modernization of California's generation fleet is under way. More than 2,100 MW of capacity that was more than 40 years old have been retired or is scheduled be retired by the end of 2003, another 825 MW that are more than 30 years old is also being taken off-line by 2004. Many of the older plants still in service can be expected to retire during the remainder of the decade, largely for economic reasons. Careful maintenance and upgrades over their lifetimes have extended their service lives, but they will become increasingly unable to compete with newer, more efficient plants in the marketplace.

**Table 3-1**
**Role of Gas-Fired Generation in Serving 2002 Load by Age of Unit**

| On-line Date | Capacity (MW) | | 2002 Gas-Fired Generation (GWh) | |
|---|---|---|---|---|
| **1940s** | 285 | 1% | 460 | 1% |
| **1950s** | 3,568 | 12% | 7,074 | 8% |
| **1960s** | 9,607 | 31% | 19,542 | 22% |
| **1970s** | 5,511 | 18% | 8,929 | 10% |
| **1980s** | 3,965 | 13% | 23,232 | 27% |
| **1990s** | 2,742 | 9% | 14,296 | 16% |
| **2000-** | 5,210 | 17% | 14,077 | 16% |
| **Total Gas-Fired** | 30,888 | | 87,610 | |

*Gas-fired plants 10 MW or larger, as of 12/31/02

**Table 3-2**
**Capacity Additions and Retirements California, 2000 – 2003 (MW, Calendar Year)**

| Calendar Year | Additions | Retirements |
|---|---|---|
| 2000 | 59 | 285 |
| 2001 | 2,329 | 396 |
| 2002 | 2,970 | 423 |
| 2003* | 4,011 | 1,252 |
| Total | 9,369 | 2,356 |
| Net Additions | 7,013 | |

Includes all plants expected to be on-line or retired by August 1, 2003
Source: Energy Commission Staff

## Natural Gas Infrastructure Affects the Electricity Market

Several factors have led to both an increasingly important role for natural gas as a generation fuel and an integration of the natural gas and electricity markets. Natural gas prices increasingly impact wholesale energy costs; shocks are transmitted from one market to the other.

Well over 90 percent of the generation capacity added in California and the remainder of the Western Electricity Coordinating Council (WECC) during the past twenty years is fueled by natural gas. Environmental, safety, or economic concerns have precluded the addition of nuclear, hydro, coal- and oil-fired generation. We expect that in 2006, for the first time, natural gas will surpass hydropower as the West's largest single generation energy source. The declining costs of production using gas-based technologies have offset similar reductions in the cost of renewable energy sources. As a result, the cost of meeting growth in electricity demand is driven by natural gas prices.

A combination of economic and environmental reasons has limited the use of fuel oil distillates as a substitute for natural gas in power generation. A large share of California's generation capacity was once able to generate using either fuel oil or natural gas; only a handful of facilities remain able to do so. The use of fuel oil had historically placed a competitive cap on the price of fuel for a particular generator. Having an alternate fuel also protected generators from natural gas curtailments, since using natural gas for electric generation was a lower priority than for end-use consumption. At high prices for natural gas, generators could burn fuel oil instead, lowering their generation costs. This alternative no longer exists, meaning that fuel costs for electric generation have increasingly been linked to natural gas prices.

Whenever natural gas is "on the margin," the price of every traded megawatt of electricity is driven by the natural gas price. If electricity prices are low relative to the price of natural gas, the generator makes greater profits by selling the gas in lieu of generating electricity. This is the case even if the generator has purchased the gas at a much lower price than currently prevails in the spot market, e.g., under a longstanding fixed-price contract. These results follow from merchant generators not having an obligation to serve loads

The link between the price of natural gas and electricity means that cycles in and shocks to natural gas prices are transmitted to electricity markets:

- Short-term supply shocks (e.g., pipeline disruptions in the western US, hurricanes in the Gulf of Mexico) and spikes in demand (a cold storm in the Pacific Northwest) mean higher spot prices for electricity in California markets. Events in the eastern US affect California as regional gas markets are integrated by the nation-wide pipeline system; gas marketers in western Canada and the Rockies have the option of shipping gas east or west and do so in response to spot market prices. The events need not actually occur for electricity prices to be affected; the gas market will often react in expectation of them. Because of their brief duration and unanticipated nature, these shocks have short-term effects (day-ahead to balance-of-month) but do not impact longer-term markets.

- Annual cycles in and shocks to the gas market include higher winter prices due to the use of natural gas to meet heating loads, and price swings resulting from changes in the amount of gas that is put into storage. The increased use of natural gas to meet peak summer electricity needs can occur at the cost of putting gas into storage. If storage levels are low during the spring and summer, prices in gas markets increase as a greater storage need competes with immediate consumption, and winter prices are higher as there is less gas in storage to be withdrawn. Increased integration has led the gas market to react to expected conditions in the electricity market: predictions of poor hydro conditions lead to higher spot and forward prices for gas. These swings affect forward gas markets through the end of the next heating season or water year and, through them, all shorter-term trades.

- Longer-term swings in gas exploration, development and production result in similar cycles in electricity prices. As gas prices fall, producers cut back, driving prices higher. Production and development resume, sending prices down again. This "boom and bust" phenomenon is similar to the one observed in electricity markets, where investment in new generation capacity leads and lags growth in demand. The cycle is arguably shorter in the gas industry as gas can be stored in the ground and "construction" is less capital intensive and has a shorter lead time. This cycle has a substantial impact on prices negotiated for electricity under long-term contracts; even though this may be a two- to three-year cycle it can influence expectations regarding long-run prices. The price volatility associated with this cycle is the primary driver of the price premium needed to assume price risk under long-term, fixed-price contracts or, equivalently, the cost of hedging it.

- A long-term decline in North American gas reserves could lead to increasingly higher prices over the next thirty years. If exploration, drilling and extraction costs increase due to the depletion of the most easily accessible reserves, long-term prices will increase. The opening up of additional basins (e.g., the MacKenzie Delta in western Canada, Alaska) might slow the increase, but will entail higher costs nevertheless.

## Transmission Links Generation to Load

California is criss-crossed by 31,270 miles of bulk electric transmission lines, along with its supporting towers and substations. The transmission system links generation to load in a complex electrical network that must balance supply and demand on a moment by moment basis. An efficient transmission system not only helps deliver the lowest-cost generation to consumers, but also facilitates markets to stimulate competitive behavior, pools resources for ancillary services, and provides emergency support in the event of unit outages or natural disasters.

Most of California's electric transmission system was originally built to connect generating facilities to major load centers in the Los Angeles, San Francisco, and Sacramento areas. Thermal generating facilities, such as large gas-fired and nuclear plants, have been built near the coast or in nearby valleys close to the load centers, thereby requiring relatively short transmission lines. Hydroelectric facilities in the Sierra Nevada have typically been some of the most remote sources of generation in the state. Each of the state's investor-owned utilities (PG&E, SCE, and SDG&E) designed, built, and operated its own system to meet the needs of its customers.

Until the mid-1960s, the three IOUs operated their transmission systems as islands, with only a few small ties between utilities. As California's dependence on oil and gas generation increased, and licensing of large generating stations was increasingly difficult, the IOUs began planning and building higher-voltage, long lines to neighboring states. The 500 kV transmission lines were built primarily for importing hydroelectric power from the Pacific Northwest and thermal generation from the Southwest. While these transmission lines provided access to less costly out-of-state power, they also provided the additional benefit of emergency interconnection support among the state's utilities to avoid potential wide scale power disruptions. The 1965 East Coast blackout that affected almost 30 million people and prompted the creation of the North American Electric Reliability Council (NERC) highlighted the need to strengthen ties between utilities as a means of promoting a more reliable interconnected system. Between 1968 and 1974, California utilities built or participated in the construction of about 3,700 miles of 500 kV lines to access remote generation. Since the 1980s only two additional 500 kV projects have been built to access out-of-state resources, and both of these projects were initiated by California municipal utilities.

While inter-state connections have not been built, intra-state transmission upgrades have been made to serve new load, reduce local congestion pockets and improve overall efficiency. Since 2001, California's utilities have been authorized by the Public Utilities Commission to invest $2.34 billion in such upgrades.

California's current bulk inter- and intra-state transmission system is shown in **Figure 3-2**. The map highlights the paths that are most heavily utilized and whose expansion may thus provide significant benefits. The map also shows major substations and the three nuclear power plants owned by California's IOUs.

With the passage of AB 1890, which restructured California's electricity industry, the California Independent System Operator (CA ISO) was formed to operate the state's wholesale power grid covering 25,526 miles (approximately 75 percent of the state) provide open and nondiscriminatory transmission service; ensure safe and reliable operation of the grid; and operate energy and reliability markets. The individual IOUs and participating municipal utilities continue to own their lines and continue to be involved in transmission planning by filing annual transmission expansion plans with the CA ISO. The CA ISO's coordinated planning process integrates the individual plans to ensure reliability at a minimum cost, as well as to ensure that expansion projects do not negatively impact the western regional grid.

The state has three other control areas which provide similar functions. The Los Angeles Depart of Water and Power (LADWP), the Sacramento Municipal Utility District (SMUD), and the Imperial Irrigation District (IID) have chosen to serve their own customers, but they must coordinate with the CA ISO and other Western control areas.

Concerns regarding transmission system obstacles and incentives for its development and the possible costs and benefits of specific upgrades are discussed at the end of this chapter, in Chapter 6 and are amplified in Energy Commission staff report entitled ***Upgrading California's Electric Transmission System: Issues and Actions***, being released shortly after this report.

# Current Conditions in the California Electricity Market

The combined effect of the capacity additions and reduced demand was an increase in the state's expected peak operating reserve margin under normal conditions in the summer 2003 to 20 percent. This compares to the roughly 7 percent needed to meet reliability criteria and avoid a Stage 1 emergency. Sufficient capacity currently exists through 2005 to meet 1-in-10 year peak loads with a 7 percent operating reserve margin. For updated reports and details regarding the assumptions underlying this estimate, see the Energy Commission website (www.energy.ca.gov).[3]

While concerns remain regarding the performance of the California electricity system in the long-term, the measures taken to stabilize the market during the past two years have been successful. Since July 2001, the California electricity market has returned to its pre-crisis performance levels of reliable delivery and moderate spot market prices for the small increments of power needed but not bought under long-term contracts.

## Reliability

**Figure 3-3** illustrates that system reliability, as measured by the number of CA ISO-declared emergencies, has dramatically improved since mid-2001.

The events in 2002 and 2003 are notable for the circumstances under which they occurred. Neither reflected an inadequate amount of capacity to meet energy demand:

- In 2002, peak temperatures, combined with reduced transmission capability from the Northwest, caused a Stage 1 alert on July 9, reducing the price cap for spot market energy to $57.14/MWh. A large number of forced plant outages the next day, combined with continued high temperatures and reduced transmission capacity from the Pacific Northwest, resulted in a Stage 2 alert. Declaration of this emergency allowed 1,400 MW of load to be voluntarily curtailed and reserves to be restored to required levels.

- On May 28, 2003, demand in the CA ISO exceeded the day-ahead forecast by 4,400 MW due to an unexpected temperature spike. As a result, more than 11,000 MW of capacity excused from participating in the market ("economic outages") and another 3,200 MW out for scheduled maintenance was unavailable. Had even a fraction of this capacity not been off line, the emergency would not have occurred.

**Figure 3-2**
**Major Transmission Paths**
**230 – 500 kV**

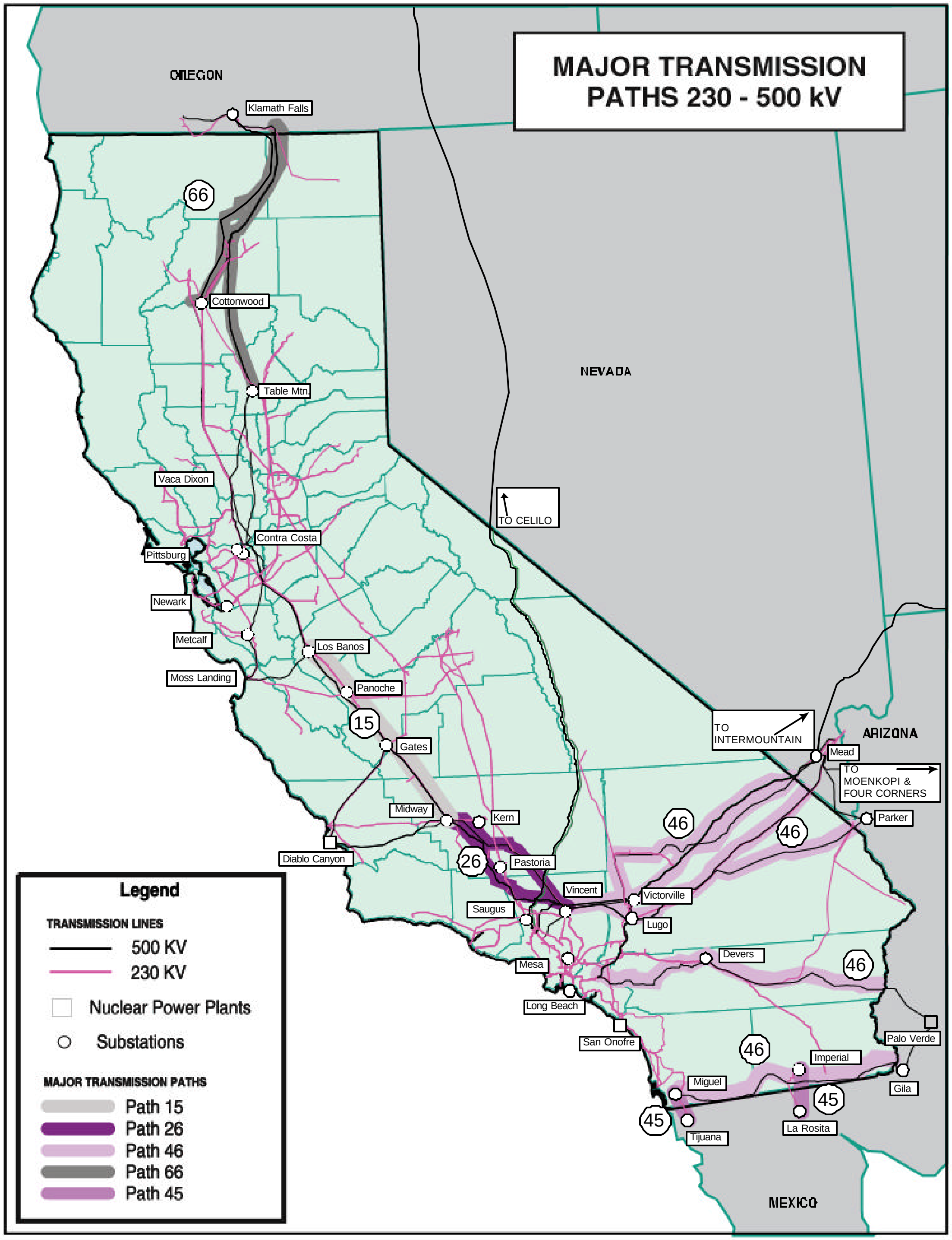
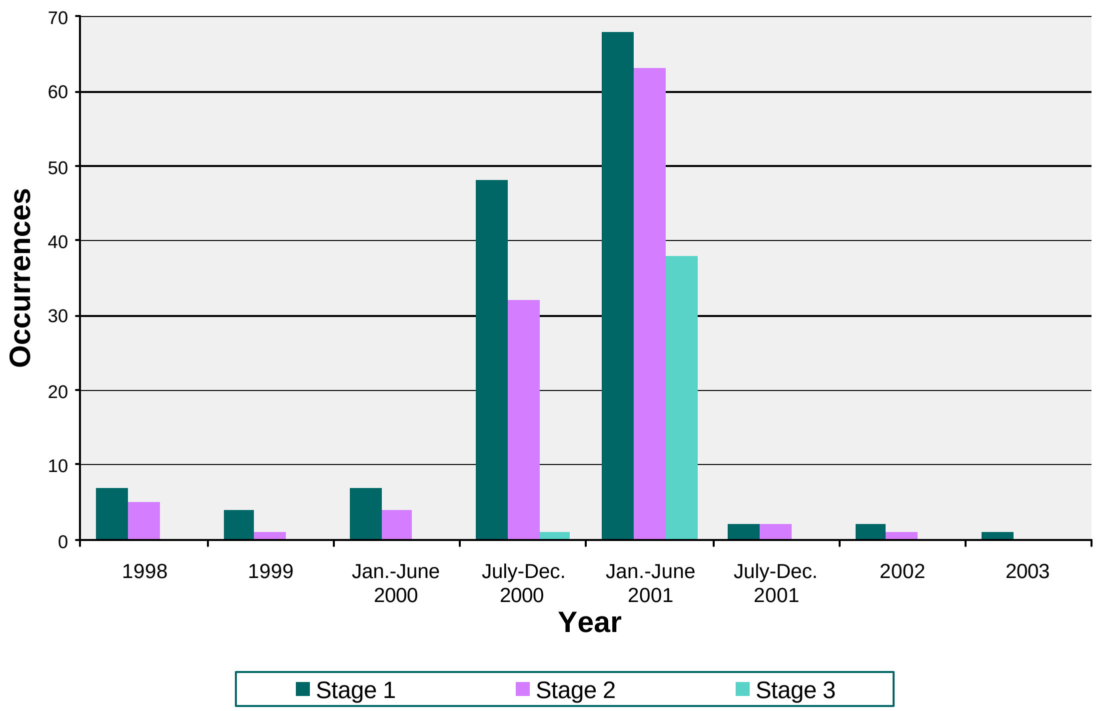


**Figure 3-3**
**Emergencies, California ISO Control Area, 2001 – 2003**




## Spot Market Prices

The trend in spot market prices is a key indicator of both supply adequacy and market conditions.[4] Wholesale spot market prices in California have been moderate since July, 2001, as evidenced by **Figure 3-4** and noted in the CA ISO's numerous market assessments.[5] Spring 2003 saw prices rise due to run-ups in the natural gas price in California and nationwide. These gas prices have been caused by low storage levels and fears that insufficient amounts of natural gas will be available to meet heating needs this winter; this is discussed in detail in the Energy Commission staff's *2003 Preliminary Natural Gas Market Assessment*. Unlike the price run-ups of 2000 - 2001, these increases do not appear to be due to shortages of generation capacity or dysfunction in either the electricity or natural gas markets. Increases in gas storage levels in June and July 2003 have caused both gas and electricity prices to ease somewhat and recent increases in exploration, drilling and production are expected to bring prices down in mid-2004. Concerns remain, however, that national natural gas prices may not return fully to previous levels. These higher prices will ripple through the electricity sector.

## The Importance of Spot Market Prices

In contrast to 1998 – 2000, very little of California's electricity market needs are currently met through spot market purchases. Beginning with the DWR contracts in early 2001, an increasing share has been and will be purchased under long-term contract, providing both price stability and incentives for developers to build new capacity. Nevertheless, spot market prices are a key indicator of the health of the electricity market. In addition to reflecting the cost of real-time purchases, spot market prices serve the following functions:

- Spot market prices provide a signal of the need for new capacity. High spot market prices relative to production costs indicate that new power plants will be profitable. In the absence of relatively high anticipated spot market prices ("forward prices"), new capacity will not be forthcoming without a long-term contract.
- Spot market prices establish the real-time benchmark against which capacity is dispatched and provide cost-saving opportunities for utilities with portfolios that are flexible enough to take advantage of them. If spot market prices are lower than the cost of dispatching a power plant or exercising a contractual power purchase, then the spot market purchase will be made instead.
- Spot market prices can indicate that generators are exercising market power. If the market is clearing at prices not warranted by production or opportunity costs, this may be a sign that generators are able to sustain prices at non-competitive levels.

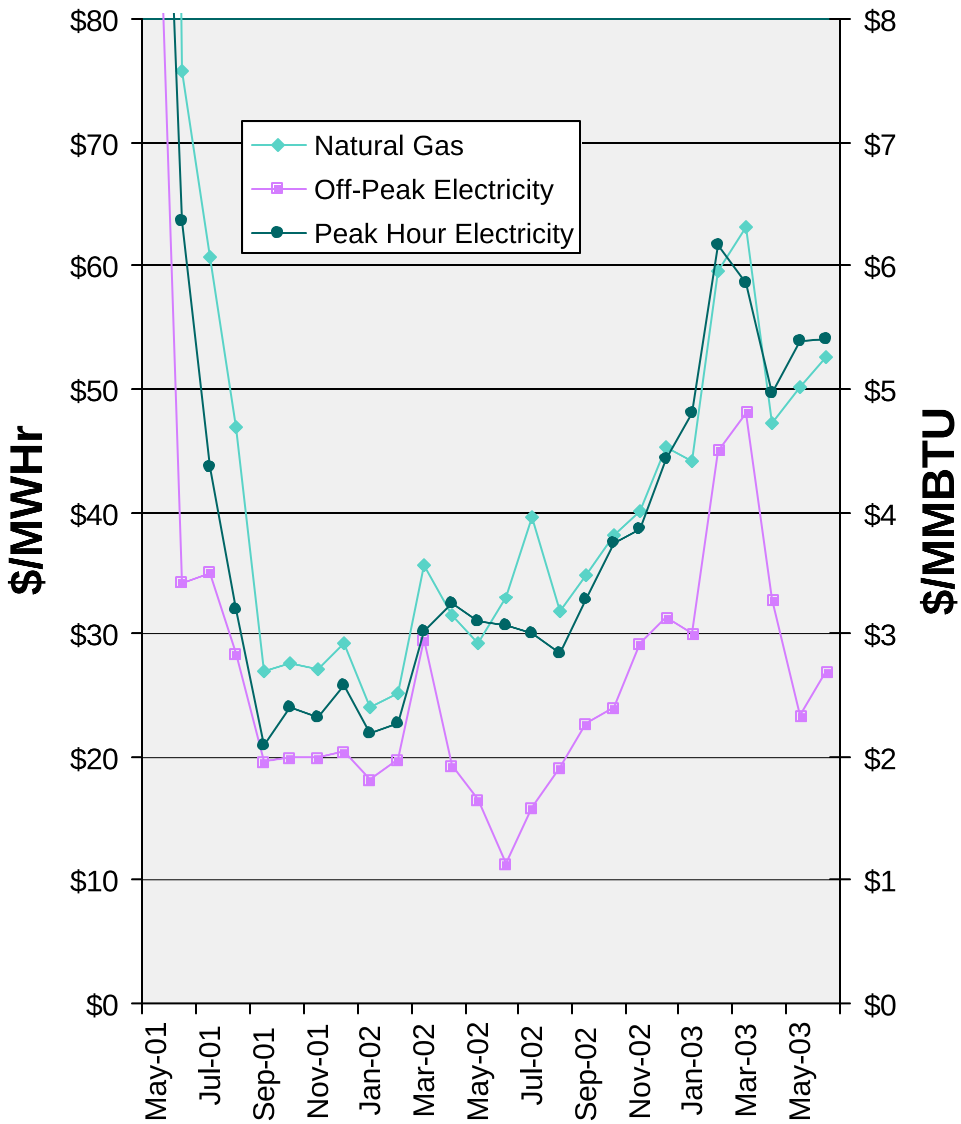
The stabilization of the spot market for electricity in California has been largely the result of three factors:

- Conservation by California consumers, their adoption of energy efficiency measures and a slowdown in the economy. Despite the growth in population, 2003 forecasted peak loads are about the same as the 1999 peak.

- The addition of more than 9,369 MW of new capacity (7,013 MW net) in the state between 2000 and 2003, as illustrated in **Table 3-1**.

- A dramatic reduction in the amount of energy purchased in the spot market by load-serving entities in California. As documented in CA ISO monthly reports, the spot market has shrunk dramatically. Most of the energy needs of the investor-owned utilities in the state are being met by utility-owned resources, contracts with QFs and other utilities, and long-term contracts signed by the State's Department of Water Resources in 2001. Additional energy needs are being met by contracts being entered into as part of the interim procurement proceedings being conducted by the California Public Utilities Commission.

**Figure 3-4**
**Monthly Average Prices, SP15 Delivery**[6]
**May 2001 – May 2003**




Source: Economic Insight, Inc. market surveys, published in *Energy Market Report* and Natural Gas Institute survey data

# Projected Supply/Demand Balance through 2006

Staff believes that loads will be reliably served (largely through LSE owned-generation and long-term contracts) and that spot market prices should remain at competitive levels through 2004 - 2006. This conclusion is based on an assessment of the current supply-demand balance, expectations regarding load growth, capacity additions and retirements, and a decreasing reliance on the spot market for energy.

Dependable reserve capacity in California and the remainder of the WECC is at a high level not seen since the late 1980s. **Table 3-3** presents the state's projected reserve margins for 2004 – 2006; a more detailed representation of this table appears in Attachment 10. For the most current outlook, see the Energy Commission's website at www.energy.ca.gov/electricity.

**Table 3-3**
**2004 – 2006 Statewide Supply/Demand Balance**
**(MW)**

| | Aug-04 | Aug-05 | Aug-06 |
|---|---|---|---|
| **Existing Generation** | 57,434 | 56,956 | 59,152 |
| **Forced and Planned Outages** | -3,750 | -3,750 | -3,750 |
| **Retirements** | -1,191 | 1,054 | 2,385 |
| **Net Firm Imports** | 5,895 | 5,748 | 5,848 |
| **Additions** | 713 | 3,000 | 1,096 |
| **Spot Market Imports** | 2,700 | 2,700 | 2,700 |
| **Total Supply (MW)** | **61,801** | **63,600** | **62,411** |
| | | | |
| **1-in-2 Summer Demand** | **53,331** | **54,500** | **55,487** |
| **Projected Operating Reserve (1-in-2)** | **16%** | **17%** | **12.5%** |
| | | | |
| **1-in-10 Summer Demand** | **56,571** | **57,811** | **58,858** |
| **Projected Operating Reserve (1-in-10)** | **9%** | **10%** | **6%** |
| | | | |
| **Emergency Response Programs/ Interruptible** | **1,102** | **1,102** | **1,102** |

Note: Does not include an estimate for new DSM or dynamic pricing demand reductions. August 2003

## Generation Additions

- Net additions during 2004 – 2006 are not expected to keep pace with load growth. Many plants currently before the Energy Commission are proposed by municipal utilities. These entities have both the need and the financial capability to acquire new resources. Several of these projects replace existing facilities that have been or will be retired; others will cover short positions during peak hours year –round or during the summer. These 6 projects and two smaller plants proposed by municipal utilities total 1528 MW (see **Appendix A, Table A-20**). In addition, two major projects being undertaken by the Los Angeles Department of Water and Power (LADWP) and the Salton Sea 6 geothermal project, which has contracted with the Imperial Irrigation District to provide up to 170 MW for 20 years are expected to be constructed. Projects proposed by the cities of Pasadena and San Francisco and the Kings River Conservation District are expected to be completed.

- The 2004-2006 projections assume the mid 2005 completion of one of the two major projects being considered for the San Diego area. These are Otay Mesa (Calpine, 510 MW) and Palomar (Sempra Energy, 546 MW). The state has step-in rights on Otay Mesa, allowing it to take over construction in the event that the developer does not meet certain milestones. In addition, the CPUC is considering a request by the California Power Authority (CPA) to require San Diego Gas & Electric to sign a long-term contract with Calpine for the output of Otay Mesa, which would allow the CPA to provide the capital necessary to complete the project. The Palomar was permitted by the Energy Commission in August 2003. The completion of 500 MW of merchant generation in Southern California in each of 2005 and 2006 is also assumed.

- The 2004-2006 projections include the development of new renewable facilities, partly in response to the Renewable Portfolio Standard established under SB 1078 (Sher, Statutes of 2002). While existing facilities may meet a share of the RPS requirements in the short-run, the past year has witnessed both new merchant development and announcements by municipal utilities of new projects. The load-resource projections for 2004 – 2006 assume the addition of 254 MW of dependable renewable capacity to meet RPS targets by summer 2006.

## Trends in Retirements of Older Generating Units

New power plants, demand-side management programs, and energy efficiency measures not only help to meet California's energy needs, but reduce the amount of hours aging power plants are dispatched. The economic displacement of generation from, or complete physical replacement of, older, less efficient power plants results in lower wholesale electricity prices, potential reductions of air pollutant emissions, and reductions of global climate change emissions in California or throughout the West.

Since 2000, 2356 MW of generation capacity in California has retired (see **Table 3-2**). Some of this capacity has been retired as owners decided the cost of installing mandatory emission controls, in addition to other going-forward costs, was uneconomic given projections of future income. Much of this capacity and that expected to be retired during the next 18 months is being replaced with new plants that are both more efficient and meet the strict emission control standards for new facilities.

The retirements assumed in **Table 3-3** during 2004 – 2006 are listed in **Appendix A**. The continued operation of most of these plants would require that emission controls be installed; expected income from continued operation is assumed to be insufficient to warrant doing so.

At present, staff believes that the shortage risk associated with additional retirements during 2004 – 2006 is minimal, despite the age of the existing generation fleet. **Table 3-3** indicates that, even if retirements exceed anticipated levels by 1,200 MW during 2004 – 2006, the expected operating reserve during the summer peak will be above 10 percent (for 1 in 2 demand level).

The continued operation of older power plants during the next three years will be facilitated by the following:

- An increasing number of plants are apt to be provided capacity contracts during the next two years. This could result from resource adequacy requirements imposed upon load-serving entities in California by regulators, or CPUC approval of capacity contracts as a component of risk-mitigation strategies pursued by the IOUs. The payments from these contracts, to the extent that they cover going forward costs, will encourage older facilities to remain on-line.

- Several older plants have DWR or reliability-must-run (RMR) contracts, including major facilities in the San Diego and San Francisco areas. Those facilities paid under RMR contracts are highly unlikely to shut down unless and until their reliability function is provided by a new plant or no longer needed due to upgrades to the transmission system.

- The cancellation of numerous development projects and delays in bringing additional capacity on line mitigates against the retirement of existing plants. While short-term revenue projections may lead to temporary shut-downs, even these facilities will remain available with sufficient notice. Increased congestion on transmission lines which move power into the greater Los Angeles area, combined with delays in completing several new plants in Southern California, raises the possibility of a wholesale electricity price premium during peak hours in the summer in the near-term for generation located in SP15.

## Reduced Dependence on the Spot Market

During the next three years, the use of the spot market for energy needs will continue to decline. Reduced spot market needs, accompanied by increases in reserve margins, both in

California and the remainder of the WECC, mean that more megawatts of capacity will be chasing fewer megawatt-hours of demand. This served to discipline the spot market in mid-2001[7] and the Energy Commission expects it to continue to do so, given the following:

- The CPUC will authorize IOUs to enter into forward contracts for energy and capacity. It is anticipated that the spot market needs of the IOUs during the summers of 2004 – 2005 will be more than 1,000 to 2,000 MW in only a handful of hours.

- Municipal utilities continue to rely upon their own plants and long-term contracts to meet a majority of their needs. They plan to add sufficient capacity and contract forward so as to offset retirements and expiring contracts.

- Direct access consumers appear to be served by a mix of mid-term contracts and the spot market. Assuming that the direct access market remains roughly the same size, the spot market requirements of these entities during peak hours will not put additional pressure on prices in the near-term, given existing reserve margins.

# Near–Term Risk Factors

This section assesses the risk factors of delivery interruptions and high or volatile prices during 2004 – 2006 and measures that can be taken to reduce them. These risks can be mitigated by continuing to contract forward for energy and capacity needs, using financial hedges to reduce exposure to possible high electricity and natural gas prices, and reducing demand with DSM and load-reduction programs. Collectively, these measures will increase the amount of generation capacity available to meet peak summer demand and minimize the likelihood and consequences of spikes in spot market prices for electricity and natural gas.

The following are the significant risk factors facing the electricity market during 2004 – 2006:

- The failure of generators to participate in the California market,
- Fewer generation additions than anticipated,
- More retirements than expected,
- A failure to resolve local reliability concerns in the San Diego area, and
- Spikes in the spot market price for natural gas

These infrastructure risks are also affected by market structure concerns such as: utility credit worthiness, merchant generation financing, the CA ISO's market redesign, and regulatory outcomes.

## Risk Factor: Failure of Generators to Participate in California Market

Threats to reliability or increased spot market prices due to capacity withholding or the commitment of energy and capacity to neighboring states are unlikely because:

- Performance requirements have been put in place by the FERC (through the CA ISO) and the legislature (through the CPUC) to increase the incentives for market participation.

- High reserve margins limit the ability of generators to sustain non-competitive prices. There is no incentive to withhold capacity or offer power at prices well in excess of production costs.

- Reduced reliance on the spot market puts further downward pressure on prices, as a relatively large amount of capacity is competing to meet demand in the spot market.

- The addition of 8,390 MW of new capacity in the Southwest during 2001 - 2003, coupled with a dramatic improvement in the supply-demand balance in the Northwest, lowers the risk that California generators will be used to meet energy needs in neighboring states during the summer at the expense of reliability in California.

The state can facilitate participation by generators in California energy markets in the near-term by continuing to allow and encourage Load Serving Entities to forward contract for energy and capacity. Using firm contracts to encumber capacity reduces the amount of capacity that is at risk for non-participation, as well as limits exposure to high spot market prices should a sufficient share of the remaining capacity fail to offer itself into the market.

## Risk Factor: Fewer Generation Additions

The number of capacity additions included in our assessment during 2004 – 2006 is conservative. It is assumed that six permitted projects larger than 300 MW (totaling almost 3,500 MW), as well as two additional projects for which approval has been recommended (1,633 MW) will not come on line by 2006, despite the possibility that one or more will do so. Moreover agency, utility and stakeholder commitment to an effective Renewable Portfolio Standard provides a reasonable basis for assuming that new renewables will be constructed. Accordingly, staff assesses the risk that these projections will prove to have been optimistic as low. A primary threat to reliability is a possible failure to bring a new facility on line in San Diego by 2006. This is discussed in greater detail below.

As mentioned above, generation additions in the near-term can be facilitated by encouraging load-serving entities to sign contracts of long enough terms to warrant the development of new facilities. Given the time necessary to complete the procurement process and the two-year lead time to develop peaking capacity, this would suggest that utilities issue RFPs before the summer of 2004 to ensure its availability by summer 2006. The CPUC procurement process is on schedule to meet this target. The resolution of outstanding issues related to the procurement process before the end of 2004, including allowing the IOUs to enter into long-term contracts, will enable new capacity to come on-line by the time that it is needed.

## Risk Factor: More Retirements

Several large power plants are required to install emission controls during 2004 – 2005. Spot market price forecasts indicate that it may not be economic for the owners of several of these plants to do so. The plants are Potrero 3 (207 MW), Pittsburg 7 (710 MW) and Contra Costa 6 (345 MW), all located in the greater San Francisco Bay Area. For more details on the aging power plant fleet, see the Staff Paper, *Aging Natural Gas Power Plants in California (*Publication number 700-03-006.

Preliminary studies by the CA ISO indicates that RMR requirements in the greater San Francisco Bay Area may be reduced substantially in 2005. This would occur if planned upgrades to the Tesla-Newark 230 kV line are completed by PG&E. Under these circumstances, Contra Costa 6 and Pittsburg 7 may be unlikely to recover emission control installation costs in a competitive bid to provide reliability services. In 2005, planners should examine whether there are any reasons that these plants need to be maintained. Even if these units are retired, the expected reserve margin during peak summer hours in 2005 remains large enough to avoid CAISO-declared emergencies.

## Risk Factor: Local Reliability in the San Diego and San Francisco Areas

The most significant reliability uncertainty in California in the near term is the potential for capacity in San Diego being inadequate to meet the area's local reliability needs. On May 16, 2003, San Diego Gas & Electric (SDG&E) issued a Request for Proposals (RFP) for 69, 189, and 291 MW of local capacity in 2005, 2006 and 2007, respectively to meet reliability needs. At least 100 MW of new capacity is needed in San Diego by summer 2006 and an additional 100 MW by 2007, to meet local reliability requirements.[8] Proposals were due to SDG&E on June 27. Final contracts will be submitted to the CPUC in September, 2003.

There are two major projects under development that, if completed, could provide the necessary capacity. Otay Mesa has been permitted; construction has begun but is delayed due to financing problems. Palomar was also permitted by the Energy Commission in August 2003. It is anticipated that both of these projects will respond to the RFP, along with developers proposing smaller facilities.

The state must ensure that the capacity necessary in San Diego is built in a timely fashion. This entails an agreement between SDG&E and one or more developers that allows SDG&E or another entity to step in and complete construction should specific milestones not be met.

There are also local reliability concerns in the San Francisco area. Unless generation is added or transmission upgrades are performed, local reliability criteria for the San Francisco peninsula will be violated as soon as 2006. In addition, environmental concerns have led to a strong local desire to have Hunters Point 4 (163 MW), a forty-five year old unit located in San Francisco proper, shut down at the earliest possible date.

The Jefferson-Martin transmission upgrade would allow for a 400-MW increase in the import of power into the San Francisco peninsula. Assuming the continued operation of the other facilities in San Francisco and other planned transmission upgrades, this would allow Hunters Point 4 to be shut down and meet reliability criteria for the peninsula for the next ten years. In the absence of the Jefferson-Martin upgrade, the proposed addition of 180 MW of combustion turbines in San Francisco would not alleviate reliability concerns for the peninsula (reliability criteria would be violated as early as 2007), and thus require the continued operation of Hunters Point 4.

The state must ensure that either the Jefferson-Martin upgrade is completed by 2006 or that new capacity is added on the San Francisco peninsula by the same date.

## Risk Factor: High Natural Gas Prices

Wholesale electricity costs are affected by spot market or near-term prices for natural gas. The cost of spot market purchases, short-term energy contracts, utility-owned gas-fired generation with short-term fuel contracts, QF contracts indexed to the gas price, dispatchable DWR contracts and tolling agreements are all driven by the spot market price for natural gas.

The risk of high natural gas prices in the near-term can be mitigated to a great extent by allowing natural gas users to hedge exposure using forward contracts and financial instruments. The PUC currently allows the IOUs to buy gas forward for tolling agreements and dispatchable contracts, protecting ratepayers against sudden price spikes.

While short-term contracts (six months or less) and financial instruments can protect ratepayers against price spikes they are of limited defense against high prices due to

- Seasonal supply-demand imbalances due to adverse weather conditions (*e.g.*, poor hydro conditions, which result in more gas-fired generation during the summer)
- Price increases due to the cyclical nature of expenditures on exploration, drilling and extraction.

If poor hydro conditions or supply lags are expected, their impact is priced into short-term contracts and near-term forward markets. While longer-term fixed-price contracts provide some protection against these sources of volatility, the market for such contracts is not liquid. Substantial uncertainties regarding gas prices more than one year into the future result in longer-term contracts tending to be high-priced.

# Long-Term Assessment

Electric generation system simulation modeling was employed to assess potential long-term electricity system and market trends. This assessment examined changes in generation patterns, electricity spot market price, and natural gas use by electric generators across a number of scenarios. The scenarios are described below, followed by the assessment results.

## Market Simulations: Changes in DSM and Renewable Generation

State policy favors additional DSM and renewable resources to meet incremental demand. To test the system impacts of accelerating or stopping public investments in DSM and renewables, staff conducted scenario analyses to evaluate the longer-term impact on natural gas use and electricity market conditions of changes in DSM savings and renewable generation. The changes in demand and renewable generation are assumed to be a result of changes in Public Goods Charge (PGC) funding. In each scenario, staff simulated the WECC electricity market for the years 2004 through 2013.

## Description of Scenarios

To provide a benchmark for evaluating the impacts of changes in DSM and renewable generation, staff developed a baseline scenario characterized by the following[10]:

- Energy Commission staff's baseline demand forecast for California for 2004 – 2013

- The addition of sufficient renewable capacity to meet RPS targets. This averages slightly less than 400 MW annually and yields an average annual increase in renewable energy of 2,000 GWh. By 2013, 3,760 MW of renewable capacity is added, producing 19,450 GWh of electricity.

- Thermal additions during 2004 – 2013 across the WECC are those necessary to sustain reserve margins for each quadrant of the region at 1998 – 1999 levels. At these levels of reserves, the system is reliable on a region-wide basis; at higher levels, prices would be too low to support new capacity.

Staff developed a second scenario in which it is assumed that: (a) increased PGC funding yields additional demand reductions, and (b) 50 percent more new renewable capacity and energy is added each year under RPS-related contracts.[11]

- Annually, the Higher DSM/Renewable Impacts Scenario adds about 200 MW more DSM peak reductions and about 1,200 GWh more DSM energy savings than in the baseline (averaged over the 2004-2013 period.)

- By the year 2013, the Higher DSM/ Renewable Impacts Scenario has 19,700 GWh more energy from DSM savings (10,000 GWh) and renewable generation energy (9,700 GWh) than does the baseline.

- In the Higher DSM/ Renewable Impacts Scenario, future gas-fired resources were reduced by about 2,500 MW by 2013—700 MW fewer new additions and 1,800 MW more retirements. These changes are based on the assumption that the market will respond to a decrease in “residual” demand by cutting back on new additions or increasing retirements of marginally utilized existing units.

# Results of DSM/Renewable Scenarios

As expected, having more DSM savings and renewable energy generation decreases the amount of gas-fired energy generation, gas use, and the average annual electricity spot market price. The differences in electricity market impacts between the Baseline and Higher DSM/Renewable Impacts scenarios are discussed below. The differences in gas market impacts between these scenarios are discussed in chapter 4 and in more detail in staff’s *Natural Gas Market Assessment* (Publication number (100-03-006). The analysis identifies system impacts; the likelihood of achieving these DSM and renewable goals were addressed in separate quantitative studies. But comparison of costs and disparate categories of benefits (e.g., emissions, fuel savings) have not been made directly comparable by monetization. Thus, results cannot be used to determine which scenarios are preferable on a quantitative basis.

## Change in Generation Patterns

The changes in DSM savings and renewable generation levels in the Higher DSM/Renewable Impacts scenario affect mostly gas-fired generation, only a very small amount of fuel oil, but little or no coal-fired generation. Most of the changes to gas-fired generation occur in the output of new gas-fired additions, rather than the output of existing gas-fired power plants. This is because committed and assumed new resource additions as well as plant retirements, already displaces as much of the generation from older plants as economic or allowable by local or system reliability constraints. The generation changes are spread throughout the hundreds of power plants within the interconnected WECC area and are not confined to California.

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts Scenario displaces about 7,600 GWh of gas-fired generation in the WECC by 2007, 14,600 GWh by 2010 and 19,100 GWh by 2013. This gas-fired generation reduction amounts to about 3 percent, 5 percent, and 6 percent of annual WECC gas-fired production, respectively. Of the total WECC gas-fired generation reduction by 2013, 53 percent occurs in California, 32 percent in the Desert Southwest, 11 percent in the Pacific Northwest, and 4 percent in the Rocky Mountain region.

## Change in Electric Generation Gas Use

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts Scenario decrease the amount of natural gas consumed for electric generation across the WECC by 3 percent in 2007 and by 6 percent in 2010 and 2013. The percentage decrease in gas consumption for electric generation in California is 4, 7 and 9 percent in 2007, 2010 and 2013, respectively. The corresponding percentages for all generators in the WECC are 3, 5.5 and 6 percent, respectively.

## Change in Annual Average Electricity Spot Market Clearing Price

In the High DSM/Renewable Impact scenario, reduced demand and increased generation from new renewables led to a 5 percent reduction in the wholesale market price by 2013

Reducing dependence on gas-fired generation is likely to result in lower natural gas prices, although this effect was not quantified. Electric generation gas demand will soon be 30 percent of the total demand for natural gas in the Western United States. A 6 percent decrease in the natural gas use by generators in the western U.S. would reduce natural gas demand in the west by 1.8 percent. The effect of such a reduction on the spot market price for California natural gas would be about 1 percent.

# Electric Transmission System Assessment

A robust transmission system provides many benefits to California, including reliability enhancement and access to cheaper generation, as well as strategic benefits. Recognizing this, the state has adopted an Energy Action Plan whose goal is to "Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers." Specifically, the Energy Action Plan seeks to achieve this goal in part by upgrading and expanding the electricity transmission infrastructure and reducing the time before needed facilities are brought on line. For example, the Plan recognizes that the current CPUC Certificate of Public Convenience and Necessity process has not been updated in response to the many industry, marketplace, and legislative changes that have occurred since the passage of AB1890 in 1996. It also asks that agencies collaborate in the Energy Commission's integrated energy planning process to determine the statewide need for bulk transmission projects.

These actions are intended to resolve some of the major transmission issues currently facing California, including constrained transmission paths (both now and predicted in the future), local reliability problems in the San Francisco and San Diego areas, system security, accommodating new renewable generation which will be needed in order to meet the Renewable Portfolio Standard, public opposition, and other planning and permitting obstacles.

## Constrained Transmission Paths and Local Reliability Areas

This section briefly describes a number of areas were transmission related problems, combined with changes caused by deregulation, have contributed significantly to higher prices and reliability problems on the CA ISO-controlled grid.[12] These include four major transmission paths—Paths 15, 26, 45 and 46, and two local reliability areas - San Diego and the San Francisco Peninsula. For a map of the major transmission paths and constraints in and into California, see **Figure 3-2**.

- Path 15 provides an example of how an insufficient transmission infrastructure coupled with poorly designed electricity markets can affect electricity costs. Path 15 enables economic transfers between southern California and the Southwest and northern California markets during much of the year. The path is often constrained during heavy summer peak load periods, limiting the level of transfers between the two areas. When Path 15 is constrained in the south-to-north direction, the CA ISO is required to dispatch less efficient, higher cost generation north of Path 15 to meet northern California loads; the resulting "congestion costs" can produce significantly higher electricity price increases in northern California relative to south of Path 15. The congestion problem was exacerbated during 2000 - 2001 as strategically located generators north of path 15 were able to use their location to significantly increase prices. The CA ISO has estimated that building a third 500 kV transmission line between the Los Banos and Gates substations to relieve the problems encountered during 2000 – 2001 would pay for itself within 5 to 10 years.

  Formal CPUC proceedings on Path 15 closed in Fall 2002. In March 2003, the presiding Administrative Law Judge for the Path 15 case submitted a proposed decision recommending that the Energy Commission reject PG&E's request for a CPCN. The draft decision argued that, among other things, the proposed Path 15 expansion would not provide sufficient congestion benefits, market power mitigation or reliability benefits to justify the upgrade based on its anticipated $300 million costs. The presiding CPUC Commissioner on the case, Loretta Lynch, also submitted a proposed decision recommending that the CPUC grant a CPCN for the upgrade. Commissioner Peevey, the new CPUC President, proposed yet a third alternative decision for the CPUC to consider. Peevey proposed that the CPUC accept PG&E's request to withdraw its application for a CPCN, a request PG&E had made earlier, but which had been rejected by the presiding Commissioner. He also recommended that the CPUC find that PG&E could perform the expansion upgrades it proposed as part of the joint PG&E, WAPA, Trans-Elect agreement, without a CPCN. Finally, Peevey's proposed decision recommended that environmental assessments for Path 15 previously performed by WAPA should be accepted by the CPUC.

  On May 22, 2003 the CPUC found that the Path 15 upgrade should go forward based on the recommendations contained in Commissioner Peevey's proposed decision. The decision limited further involvement by the CPUC in the Path 15 expansion case, except in the event that PG&E increases the costs of its upgrade obligations.

- Path 26, an extension of Path 15 within Southern California, was intended to provide transfers of lower cost power from Northern to Southern California during periods of high hydro availability in the north. The path, however, is often subject to constraints that limit these economic transfers. Congestion on Path 26 has increased to such a level that the CAISO has designated it as a separate pricing zone within California.

- Path 45 connects Northern Mexico with San Diego and the Imperial Valley. New generation in the amount of 1,665 MW has been completed in Northern Mexico near Mexicali—the 600 MW Sempra Termoelectrica de Mexicali is fully commercial while the 1,065 MW Intergen La Rosita Power Project will be fully commercial by the end of summer 2003. Of this capacity, 1,070 MW are intended for export to the U.S. The remaining 590 MW will be available to Mexico (CFE). The former portion will connect through Path 45 to the Imperial Valley substation, but not all of it will be available to the San Diego area until upgrades at the substation are completed. Increasing transfers into the San Diego area will also require reinforcement of the Miguel-Mission transmission line, an upgrade which the CPUC has found needed for economic purposes and is currently moving through an expedited permitting process.

  On May 2, 2003, a U.S. District Court found that the environmental assessment associated with the presidential permit issued by the US DOE and the right-of-way grant issued by the Bureau of Land Management allowing for the cross-border transmission lines had not adequately addressed air and water quality impacts. On July 8, 2003 the judge provided for the continued operation of both new plants while giving the US DOE until May 15, 2004 to demonstrate why the court should not set aside the presidential permit.

- Path 46 connects Southern California to Nevada and Arizona. Another wave of generation development is currently occurring in the southwest, particularly in central Arizona and the area around the Palo Verde hub. Arizona expects to see more than 6,000 MW of new gas-fired generation on line in this area by 2007. Additional generation is being developed in southern Nevada. Most of this new generation capacity is intended for sale in California electricity markets. The existing transmission capacity on Path 46 - linking western Arizona and Southern California markets - is not sufficient to transport this amount of power without significant upgrades. The CA ISO has initiated a regional stakeholder process to evaluate transmission expansion options for Path 46.

  The process, known as the Southwest Transmission Expansion Plan (STEP), is a regional collaborative planning process, designed to identify transmission constraints that limit economic power transfers between areas within the southwest and propose transmission expansions to remove those constraints. The process involves grid planners from Arizona, southern Nevada, Northern Mexico, and Southern California (SCE and SDG&E). The STEP process can also be viewed as an extension of the CA ISO's Coordinated Grid Planning Study process in which the CA ISO is involved, along with stakeholder groups, in resolving constraints on the CA ISO-controlled bulk power system within California.

A study plan has been developed and two screening (power flow) studies have been performed thus far, using a 2007 base year with assumed generation additions in the Palo Verde area, southern Nevada, and Mexico. Generation additions and retirements are also assumed in the SDG&E and the SCE areas. Without any transmission upgrades, the initial screening study identified significant constraints between Palo Verde and southern California on both the Southwest Power Link (SWPL) and PaloVerde-Devers. Some 20 alternative cases were then developed to evaluate their relative effects in mitigating those constraints. Three AC and two DC cases were selected from this group for further evaluation. These cases will be refined through additional assessment. STEP is also performing an economic assessment of these five cases to identify their potential economic benefits.

## Local Reliability Areas

San Diego and the San Francisco Peninsula were both impacted by serious reliability problems during parts of 2000 and 2001. Both areas are characterized by limited generation within their electrical boundaries and limited transmission capacity to access resources outside of those boundaries. This combination of conditions has resulted in limited competition, providing local generators the potential to influence both reliability and electricity prices during heavy summer peak load conditions. To provide local voltage support for reliability purposes, as well as mitigate market power problems, much of the generation in both areas has been designated by the CA ISO as RMR. This means the CA ISO has required certain generators in San Diego and on the SF Peninsula to enter “must run” contracts that obligate them to operate at specified prices during periods designated by the CA ISO.

### San Diego

The San Diego area has about 2,250 MW of local generation. With a projected summer 2003 peak load of about 3,800 MW, it must rely on imports from outside the area to meet a major portion of its peak load requirements. These requirements are supplied by two major transmission paths, Path 44 and the 500kV Southwest Power Link (SWPL), part of Path 46. Path 44 connects San Diego with the San Onofre Nuclear Generating Station, has a transfer capability of 2200 MW, and is San Diego’s only major link with the CAISO grid. SWPL connects San Diego to generation resources at the Palo Verde hub in western Arizona. With all lines in service, the simultaneous transfer capability into San Diego is about 2,800 MW. As a part of their area reliability studies, the CAISO and SDG&E found that a sequential outage of the area’s largest local power plant and its largest transmission line, SWPL, could result in local-area reliability criteria violations beginning in the 2005 time frame. Based on those findings, they proposed the construction of a 500 kV power line to provide a second major connection to the CAISO-controlled grid in the SCE service area—the Valley-Rainbow project.

SDG&E submitted an application to the CPUC for a CPCN for Valley-Rainbow in 2001. In December 2002, after over a year and one-half of hearings and debate, the CPUC denied SDG&E's request for a CPCN without prejudice (see D.02-12-066.) The CPUC denial was based on its view that Valley-Rainbow was not needed in the five-year planning horizon it allotted for the project from the time of project submittal to construction. Following the CPUC decision rejecting Valley-Rainbow, SDG&E filed a petition for a rehearing and a petition to modify the decision with the CPUC. On June 5, 2003 the CPUC rejected SDG&E's rehearing request and its petition to modify and denied the proposed Valley-Rainbow upgrade.

On April 15, 2003 SDG&E filed its 20-year long-term resource plan with the CPUC in proceeding R.01-10-024. SDG&E proposes a two-phase transmission expansion plan that would strengthen the 500-kV "backbone" system, allowing additional imports into the southern CAISO-controlled grid from Arizona, Mexico, and southern Nevada. For this expansion to provide local reliability benefits in addition to likely statewide reliability and economic benefits, it needs to tie into SDG&E's service area. The proposed expansion includes the Valley-Rainbow upgrade (renamed the Near-Term Interconnection Project) assumed for 2008 and an additional 160-mile, 500 kV line from the (new) Rainbow Substation to the existing Imperial Valley Substation assumed for 2012. The project would significantly increase SDG&E's ability to import power from northern Mexico and Palo Verde and provide an additional connection between San Diego and the CA ISO-controlled transmission system.

New generation development or demand reduction programs in San Diego could contribute to a near-term resolution of SDG&E's reliability problems. Two large power plants have been proposed for the immediate San Diego area that could provide substantial reliability support, if completed. An application for the Otay Mesa power plant (Calpine, 510 MW) has already been approved by the Energy Commission, but the facility is still in the very early stages of construction and there is uncertainty about its near term completion. The proposed Palomar facility (Sempra, 546 MW) was permitted by the Energy Commission's in August, 2003.

## San Francisco Peninsula

San Francisco, like San Diego, has limited transmission and generation resources. PG&E currently projects peak loads of approximately 1,230 MW for the San Francisco/Peninsula area for 2005. Electricity to serve these loads is provided by six transmission lines in a single corridor and three aging and unreliable area power plants. These resource characteristics cause significant reliability risks for future outages on the SF Peninsula.

Local generation is expected to provide 618 MW of power to the SF Peninsula in 2005 (363 MW from the Potrero Power Plant, 215 MW from the Hunters Point Power Plant and 20 MW from the United Golden Gate Cogeneration Plant). All of this generation (except United Golden Gate) is under RMR contract with the CA ISO. This existing generation (expect the United Golden Gate Plant built in 1986) is also highly susceptible to problems because of age and environmental issues. The Hunters Point Power Plant will be shut down as soon as it can be displaced by new generation and/or increased imports from outside the area according to an agreement between the City and County of San Francisco and PG&E. The lack of generators and their vulnerability has also impacted the ability of PG&E to perform maintenance on the transmission facilities.

The remaining 600+ MW of power needed to meet SF Peninsula load requirements (including reserves) is imported over transmission lines from the East Bay. Approximately a third of the generation needed for the San Francisco Peninsula is served by power delivered at San Mateo Substation from 230kV transmission lines connecting the Tesla, Newark, and Ravenswood Substations. The remaining San Francisco Peninsula load is met through power delivered to San Mateo Substation via two 230kV lines crossing San Francisco Bay.

The San Francisco electric reliability problem is being evaluated in several forums. Two major facilities (one transmission line and one power plant) are currently in permitting proceedings at the CPUC and Energy Commission, respectively. A second transmission project is also in the planning stages. The City and County of San Francisco has also looked at the problem and developed an energy plan that includes transmission, generation and conservation options. Finally, the CA ISO, through a PG&E stakeholder process, is analyzing the long-term (10-years) reliability of the San Francisco and Peninsula region. The fragmented planning process is discussed in the companion report: Public Interest Energy Strategies.

Two transmission projects intended to increase electricity imports into the Peninsula have been proposed by planning groups to increase import capability into the SF Peninsula area. The San Mateo-Martin Conversion Project, an upgrade of an existing 60 kV line to 115 kV, could increase area imports by 200 MW by 2004. PG&E has not yet filed an application at the CPUC for this project, however. PG&E has filed an application with the CPUC for a CPCN for the 230 kV Jefferson-Martin transmission line. This project, along with other system improvements, would increase the import capability into San Francisco by approximately 400 MW.

Mirant has proposed a 540 MW expansion of its Potrero Power Plant that would displace existing generation on the Peninsula. “However, Mirant filed for Chapter 11 protection in U.S. Bankruptcy Court on July 14, 2003. Thus, even if the expansion project is certified by the Energy Commission, it is uncertain whether the project would be built, either by Mirant or another entity.” This project is currently in licensing review at the Energy Commission.

## Transmission System Security Issues

The CA ISO Controlled Grid is designed to meet the NERC/WECC Planning Standards. Part of the criteria associated with these planning standards requires an analysis of extreme events such as loss of an entire substation or power plant. These extreme events are to be evaluated for risks and consequences. A consequence of cascading outages throughout the WECC is unacceptable. Given the increased risk of terrorism, the risk of an extreme contingency may be higher so the need for mitigation plans may be more justifiable. The CAISO selects about 5-10 extreme contingencies to evaluate every year as part of its controlled grid study. Given the increased risk of terrorism, the CAISO is considering giving this part of the criteria more attention. Also, utilities typically carry spare equipment for responses to storms and earthquakes, and they have mutual assistance agreements and spare equipment databases. This type of preparedness and cooperation can serve to help mitigate the extreme event.

Energy Commission staff participated with the California Antiterrorist Intelligence Center (CATIC) under the California Department of Justice. The mission of CATIC was to compile a list of critical assets in the state with a view toward ranking them by vulnerability and sensitivity to terrorist attack[13]. The list compiled corresponds to a list of targets that would result in great damage and/or disruption if successfully attacked or sabotaged. Critical assets were broken down into telecommunications, water, power, government facilities, psychological/symbolic categories and more. The ranking was a systematic identification and quantification of the damage and disruption that would result from a terrorist attack on each critical asset.

Facilities were ranked on the significance of disruption with the highest category being disruption of the entire state electric supply system. Lower ranking levels of disruption included the loss in transmission links to large urban centers.

In addition the CA ISO has been following several nationwide studies on system security. Two examples include EPRI's "Electric Infrastructure Security Assessment" and "Grid Transformer Defense, Risks, Vulnerabilities and Strategic Countermeasures" a presentation to EPRI, March, 2002.

An additional action for system security could be pursued during the *2004 IEPR Update* to determine if recommendations are necessary for state action for risk or consequence reduction in the event of an extreme event related to terrorism. Staff in collaboration with the CA ISO could assess the status of system security as identified by state and federal homeland security officials and determine if appropriate actions are progressing to ensure adequate protection. Recommendations could be considered for such mitigation as expanded security for the highest priority critical assets, spare equipment data bases and equipment sharing agreements including federal government participation in stockpiling critical equipment available to California on a timely basis.

## Facilitating Existing and New Renewables to Meet the Renewable Portfolio Standard

Senate Bill (SB) 1078 (Chap. 516, Stat. of 2002) was enacted to increase California's use of renewable energy resources. SB 1078 created the Renewables Portfolio Standard (RPS) Program under which the state will increase its electrical generation from renewable sources by at least one percent annually until renewables comprise 20 percent of total investor-owned utility (IOU) procurement by the end of 2017 within certain cost constraints. If a transmission facility is an integral part of a renewables project approved pursuant to the RPS process, it creates a prima facie finding that the network upgrade will facilitate achievement of the renewable power goals established in SB 1078. The Energy Commission was charged with providing a resource assessment study to the CPUC that the CPUC would use in producing a transmission plan for renewable electricity generation facilities. The Energy Commission has provided this assessment to the CPUC, the CA ISO and stakeholders.

The CA ISO held a stakeholders' workshop on July 7, 2003 to facilitate the process of formulating a transmission expansion plan for renewable generation, based upon the resource estimates provided by the Energy Commission. The IOUs, developers and the CA ISO will work together to develop conceptual plans that the CPUC will include in their transmission plan for renewable electricity generation.

The CPUC initiated investigation I.00-11-001 in November 2000 to identify and take actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, per AB 970 (Chap. 329, Stat. of 2000). Phase 6 of this proceeding, the Tehachapi Transmission Project, is currently underway, and evidentiary hearings were held on June 9 through 11, 2003.

As part of this process, Southern California Edison (SCE) has completed conceptual studies funded by interested wind developers on the Tehachapi region. These studies have identified the substations and lines that would be required to meet the potential growth of wind resources in the region. SCE plans to conduct detailed environmental studies in 2003, and file the application for a Certificate of Public Convenience and Necessity (CPCN) around February 1, 2004.

# Chapter 4: Natural Gas Market Assessment

## Introduction

Chapter 3 introduced and described in a general way the integration of electricity and natural gas markets and infrastructure. This chapter will discuss that integration more, but with greater attention to natural gas issues.

Natural gas prices have been extremely volatile since the summer of 2000. One school of thought is that natural gas prices have at times risen due to a strong demand in the power generation sector and its ability to pass the high generating fuel prices on to electricity customers. The second school of thought presents high gas prices as a result of inadequate pipeline capacity due to increased demand for heating needs as happened during the last winter season. A third school of thought attributes high prices to the low levels of storage and the fear that the low levels would mean a tight supply situation in the coming summer and winter peaks.

Finally, the fourth school of thought directly links current high prices and the anticipation that the high prices will continue into the intermediate future because there are not as many large pools of natural gas that can be developed to sustain a level of production to match the growing demand. In this school of thought, it is believed that the new wells drilled and the new pools developed will provide supplies only for short durations of time and do not promise the lasting life as older wells and supply basins did. While the number of drilling rigs has risen, the futures prices have not yet reacted sufficiently to give the market a confidence that significant supplies will be available in the future.

A combination of volatile gas and electricity markets and anticipation of a supply shortage in spite of an increasing number of drilling rigs, have raised the fear of increased uncertainty in the energy market. These uncertainties are discussed in the following sections

Detailed analysis supporting this chapter may be found in Attachment 2: the ***Natural Gas Market Assessment*** (100-03-006). Problems and risks are discussed in Chapter 6.

## Background

Over the past 3 years, pipeline expansions and additions have enhanced the reliability of supply to regions in the state. California is currently in a position where pipeline capacity to the state will serve its needs sufficiently until about the year 2006. Beyond this year, although annual average capacity will be adequate, peak day conditions could warrant the need for more capacity. This need can be complemented by more efficient use of storage capacity by not only the residential and commercial consumers but also by the industrial and power generation markets.

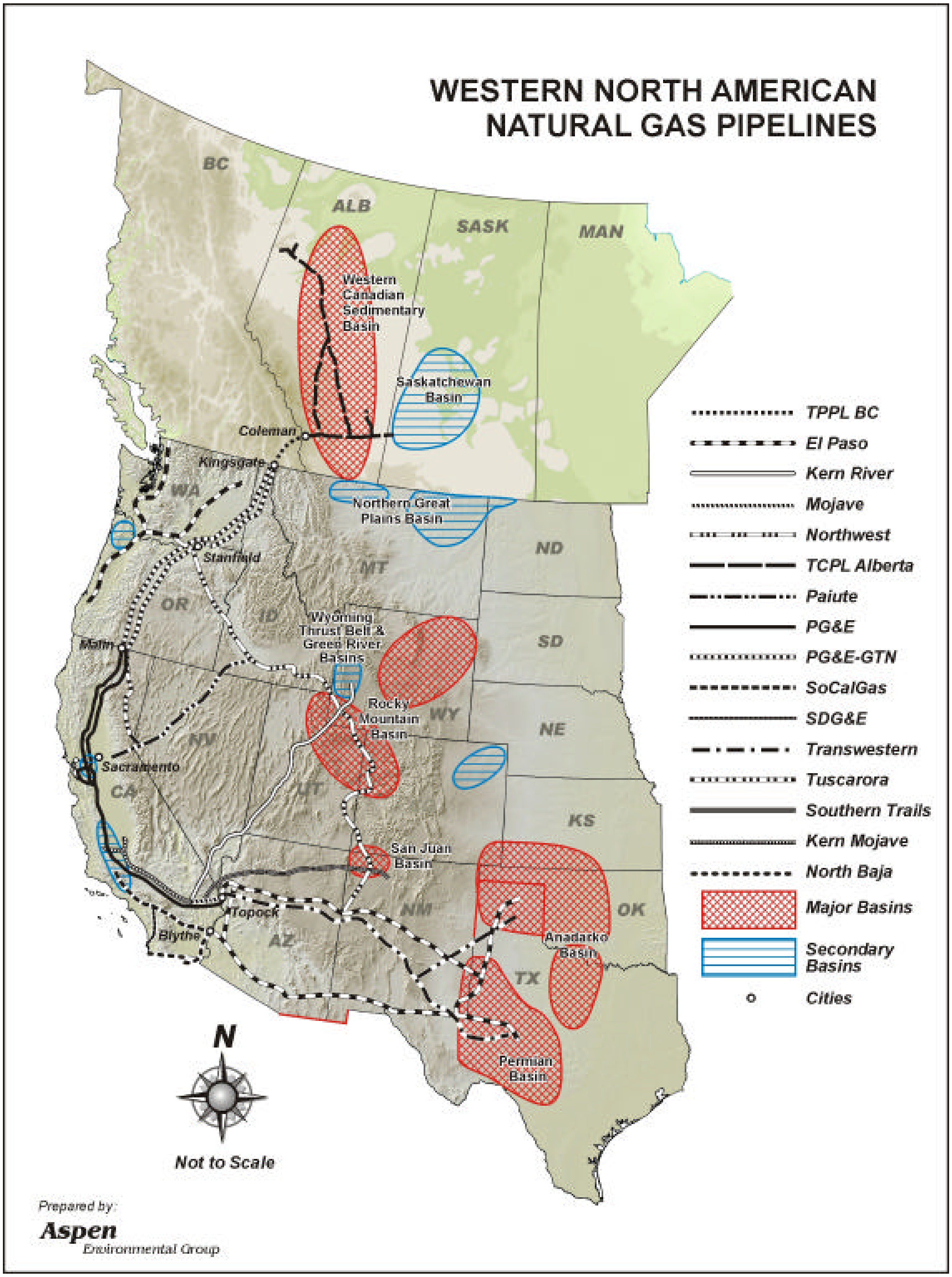
**Figure 4-1** shows the natural gas pipelines supporting California and its neighboring states. The winter of 2000-2001 turned out to be an exceptional year when demand was high and pipeline capacity was inadequate to meet peak conditions. The resulting crisis prompted action from the industry by proposing several projects that expanded or added new pipelines.

Three recently-completed interstate pipeline projects (the Kern River Expansion, the Southern Trails by Questar and the North Baja Project) coming into the state will provide significant benefits to California by improving the ability to move the gas supplies to regional demand centers. In addition, the Kern River's completed High Desert Lateral and the El Paso's Line 1903 conversion to be completed by July 2004, will interconnect a number of main pipelines and should provide additional flexibility to both SoCal Gas and PG&E. PG&E also will benefit with the 180 MMcfd expansion in 2002 of the PG&E-NEG's interstate pipeline from Canada to the California border at Malin.

Natural gas demand in the U.S. and Canada has grown and continues to grow, with power generation being the prime driver in all regions. Key parameters raising uncertainty in satisfying the regional natural gas demand are the number of proposed power plant that will be built and the extent to which each of these plants consume natural gas. If the proposed new plants are abandoned or delayed, natural gas demand will increase sooner because the older, less efficient plants will be needed to run more often. This will be true for power plants not only in California but also for those in the neighboring states. Further, California's future need for new power plants and the gas supply to serve those plants might decrease if power plants are constructed outside of California, and electricity can be imported from out-of-state facilities at competitive prices. This could increase the reliability of gas supply within the state, as demand will be less, but might divert gas to generation "upstream" from California's end users. It also raises uncertainty in depending on larger amounts of electricity supplies from out-of-state sources.

Natural gas prices in various regions of the North American continent are strongly interrelated, and changing conditions in one region influence other regions significantly. An example was the observed regional gas prices over the past winter. Colder weather and higher prices in the Eastern U.S. lifted prices on the West Coast even though demand was less than normal and pipelines were not completely utilized.

**Figure 4-1**
**Western U.S. Natural Gas Pipeline System**



# Uncertainty in the Natural Gas Market

General trends in natural gas are driven by market demand, natural gas resources and their associated exploration and development costs, transportation rates, pipeline capacities, and alternative fuel prices. There is a band of uncertainty around each of these parameters. The level of uncertainty defines the volatility in prices observed in the market place. Even though long term price and supply trends may be stable and growing slightly, price spikes and volatility occur in daily or monthly average prices. Hence, the long-term picture masks the volatility or spikes observed in the day-to-day market transactions.

Scenarios of differing supply and demand conditions were assessed to determine the range of uncertainty introduced by changes in individual parameters. The scenarios also examined how changing market conditions, over time, influence the price and supply of natural gas. Market conditions can and do cause significant seasonal disruptions, increased price volatility in the spot market, or create supply tightness on peak days. While supply and demand will come into equilibrium at all times, short-term imbalances will occur especially during peak days when the system capacity will be stressed beyond its capacity.

The observed volatility and sudden spikes or troughs are indications of the uncertainty in market prices and supply availability. Of note is that the spikes and volatility are characteristic in the daily or monthly average prices. The annual average prices, on the other hand, show changing trends in prices but mask the volatility or spikes observed in the day-to-day market transactions.

# Natural Gas Market Trends

The natural gas demand forecasts of Chapter 2 include all core customer end use demand but only a portion of non-core customer end-use demand. They exclude gas use by electric generators, who are also a part of the non-core gas customers. This section combines California's gas demand forecasts from Chapter 2 with the electric generation gas demand forecasts from Chapter 3 and other national level natural gas demand to present and examine natural gas trends under a variety of gas market scenarios.

The Energy Commission uses the North American Regional Natural Gas (NARG) Model as the principle tool to assess natural gas market fundamentals and generate the California border price forecast. Basic inputs to the NARG model include estimates of resource availability, proved reserves and expected appreciation, production costs, pipeline capacity and transportation costs, regional demand projections, and other parameters defining the market fundamentals. The basecase analysis resulting from the above inputs assumes average hydroelectricity and weather conditions and well-functioning competitive markets. Scenarios with alternative assumptions test the impacts of different market conditions on demand, price and supply availability and investigate the inherent uncertainty in the natural gas market.

The long-term assessments, examine annual gas consumption by end-use sectors under a range of scenarios. Market assessments use a base or reference case with high and low price cases designed to envelop the uncertainty in the natural gas market, providing a range of possible price trends over the next decade. The basecase describes the most likely outcome of the natural gas market over the forecast horizon. In this case, the natural gas market is that market most likely expected to occur given today's understanding of the energy market. The high and low price cases provide the bounds of gas prices. These two cases provide an indication of how high or low gas prices can reach when assumptions in the basecase deviate from their expected trend due to either expected or unexpected event changes over the forecast horizon. While these bounding trends are reachable, they are not sustainable as market forces are expected to dynamically change and impact the trends. The assumptions in high and low price cases are described later in this section.

## Demand Projections

Natural gas production, transportation and distribution are an integrated grid throughout the North American continent. Unlike electricity, natural gas market trends in one region impact other regions, even across the country. Studying the energy trends in California, necessitates analyzing natural gas markets in the United States, Canada, and Mexico. While the natural gas demand projections for the residential, commercial and industrial sectors in California are discussed in the previous chapter, this section adds the discussion of gas demand for power generation in the WECC region as well as the national natural gas demand assumptions underlying the Commission's analysis.

As mentioned in Chapter 3, electricity generation provides for the largest demand growth for natural gas of all sectors. While California's demand for natural gas in the electricity generation sector grows between one to two percent per year, national electricity generation gas demand will grow at nearly five percent per year. Growth in the residential commercial and industrial sectors in the US and in California is relatively flat over the assessment period.

Natural gas demand can be classified into three major sectors: core, non-core, and power generation. A description of the three major sectors that consume natural gas is provided in the side bar, to the right. Historically fuel switching has played a major role in the way the thirst for energy has been met at different times of the year. Natural gas, distillates, diesel, coal, residual fuel oils and propane fuels have competed for market shares, varying in type and quantity

**Demand Sector Classifications**

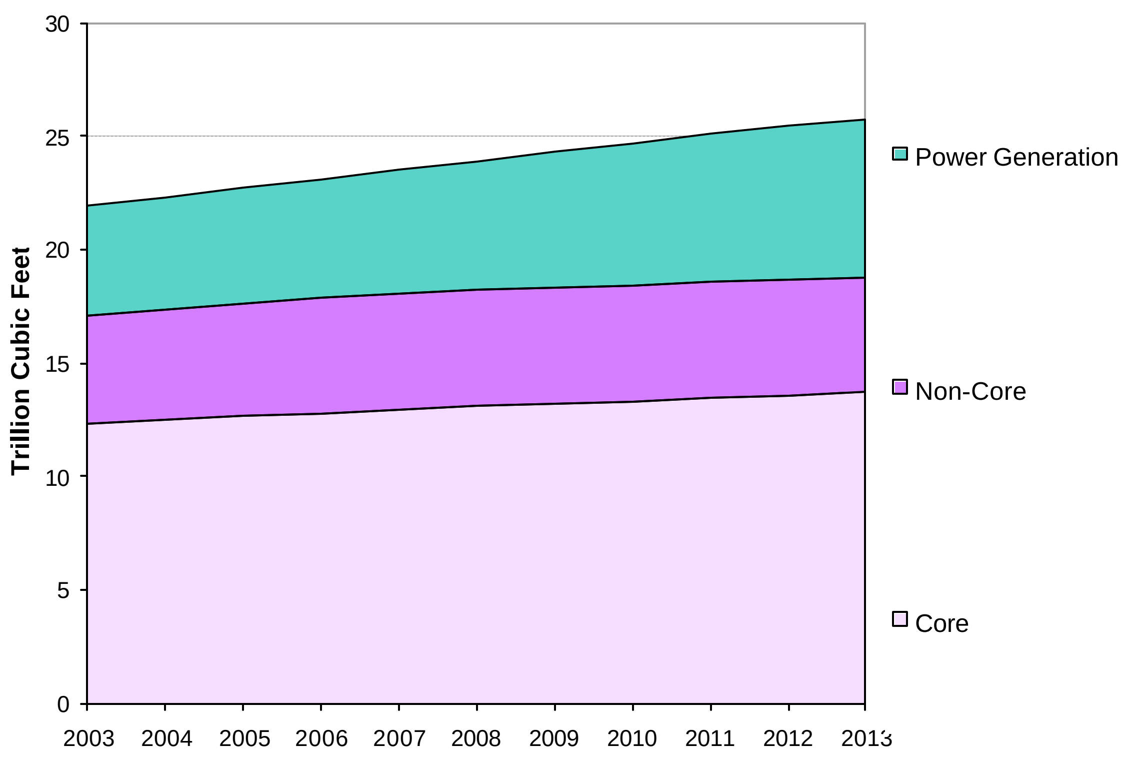
- **Core demand** consists of residential, commercial, transportation, and one-half of the industrial natural gas demand. Core customers are totally dependent on natural gas and cannot use alternative fuels, such as petroleum, in place of natural gas;
- **Non-core demand** consists of the remaining half of the industrial natural gas demand, 25 percent of commercial oil demand, and increasing amounts of industrial oil demand (20 percent in 2002, 30 percent in 2007, 40 percent in 2012, and 50 percent thereafter); and
- **Power generation demand** consists of all the natural gas demanded by electricity generation. For regions where petroleum fuel is used for power generation, oil demand is included in this category.

over the different regions and seasons. Recent environmental regulations have restricted the ability to switch between fuels in many regions of the U.S. reducing the number of regions where switching can occur. The details of regional demand and fuel switching abilities are discussed in the Staff Report on natural gas markets[14].

**Figure 4- 2** shows the core and non-core natural gas demand for the U.S. (excluding California). According to EIA's *Annual Energy Outlook 2002*, natural gas demand in the U.S. (excluding California) will grow as follows:

- **Core demand** will increase from 11.67 trillion cubic feet (Tcf) in 2003 to 12.98 Tcf in 2013, an annual growth rate of 1.1 percent.
- **Non-core demand** will increase at an annual rate of 1.7 percent between 2003 and 2013, from 4.35 Tcf to 5.12.

**Figure 4-2**
**U.S. Core and Non-core Natural Gas Demand (excluding California)**




Source: Department of Energy, EIA

Natural gas demand for electricity generation represents the fastest growing sector, according to both the EIA's projection for outside the WECC, and the Energy Commission's projection within the Western Electricity Coordinating Council (WECC). The EIA estimates that from

2003 to 2013 gas demand for power generation will grow at an annual rate of 4.6 percent compared to 1.2 percent for all other sectors. In fact, EIA projects that by 2020, electricity generators will account for 55 percent of total natural gas consumption in the United States. The natural gas demand for electricity generation in the WECC states surrounding California is anticipated to increase at an annual rate of 6.6 percent over the next decade. Specifically, gas demand for power generation will increase by:

- 7.4 percent per year in the Desert Southwest,
- 8.5 percent per year in the Rocky Mountain region, and
- 4.0 percent per year in the Pacific Northwest.

**Table 4-1** shows the growth in natural gas demand for power generation in the WECC states surrounding California, compared to the rest of the United States (excluding California).

**Table 4-1**
**Natural Gas Demand for Power Generation**

| | Trillion Cubic Feet 2003 | Trillion Cubic Feet 2013 | Annual Growth Rate (2003-2013) |
|---|---|---|---|
| Pacific Northwest | 0.18 | 0.27 | 3.96% |
| Southwest Desert | 0.26 | 0.53 | 7.43% |
| Rocky Mountains | 0.10 | 0.23 | 8.46% |
| Western States (excluding California) | 0.54 | 1.03 | 6.60% |
| United States (non WECC) | 4.18 | 6.53 | 4.57% |

Source: California Energy Commission and Department of Energy, Energy Information Administration

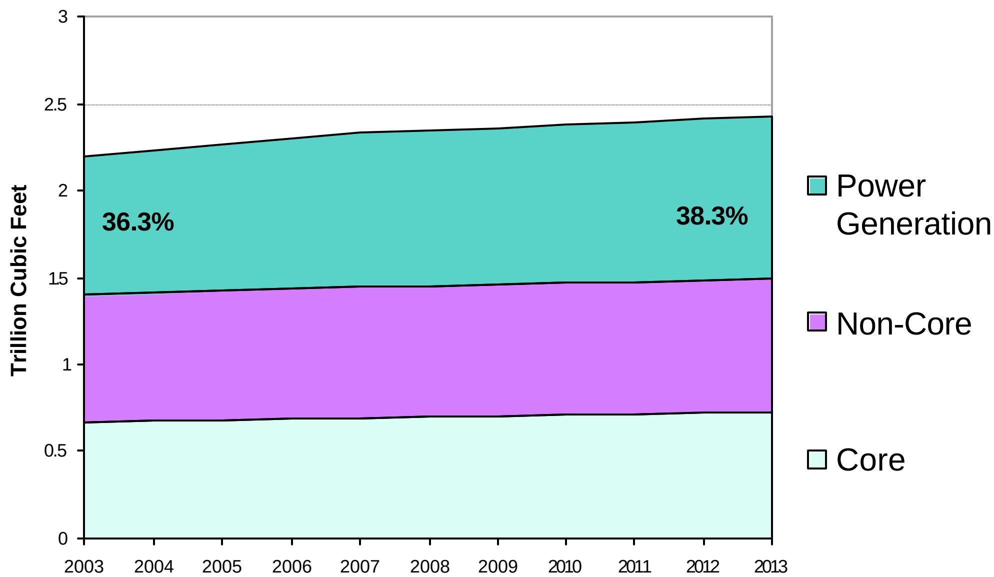
The Energy Commission's forecast for the combined core and non-core natural gas demand grows at a rate of 0.6 percent per year in California from 2003 to 2013. This represents less than half of the annual rate by which total U.S. core and non-core natural gas demand is projected to grow during the same period. From 2003 to 2013, natural gas demand in California will increase as follows:

- **Core demand** will increase from 0.66 to 0.73 Tcf, a rate of 0.9 percent per year,
- **Non-core demand** will increase from 0.74 to 0.77 Tcf, which is an annual growth rate of only 0.4 percent.

This forecast includes the impacts of natural gas energy efficiency programs, and assumes that the current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the California Legislature.

Gas demand for electricity generation remains the fastest growing segment of California's natural gas demand. Over the next ten years, natural gas demand for power generation will grow from 0.80 to 0.93 Tcf per year, yielding an annual growth rate of 1.5 percent per year. **Figure 4-3** illustrates natural gas demand in California, by sector. Total California natural gas demand grows 8 percent from 2003 to 2010. Three-fifths of this increase comes from power generation. If electricity generation gas use were held constant at the 2003 level, total demand for the state would only grow four percent.

**Figure 4-3**
**Natural Gas Demand in California, by Sector**




Source: California Energy Commission

## Natural Gas Resources and Supply Adequacy

Natural gas resources and its associated costs to explore, develop and produce are the primary drivers of the price paid in the market. The total amount of resources considered to be in the ground is more than sufficient to satisfy the growing demand for many years. The uncertainty is how much it will cost to get the gas supplies into the pipeline and delivered to its destination. One significant driver underlying the price of natural gas is the *reserve appreciation,* or the amount by which the resource grows over time. Historically, the assessment of the total amount of gas has continually grown, and the annual increase in the amount has been significant, as high as five percent in some years. In this analysis the total potential resource assumed to be available in the U.S. is about 640 Trillion cubic feet (Tcf). About 160 Tcf, in addition, is proved and currently available for production. Similarly, the amount of potential and proved resources available in Canada is assumed to be 260 and 70 Tcf, respectively.

Historically, the producers identified and developed large amounts of resources to meet the contracted or demanded quantity in the market; a resource to production ratio (R/P ratio) of about 10 was considered normal. In recent years, however, deregulation of the industry and reliance on short-term contracts and/or spot market purchases has not provided the incentive for produces to *prove* large chunks of resources. As a consequence, the developing and drilling of natural gas has become a more short-term cycle. The challenge then is to determine how quickly supplies can come to the market and whether the quantity is sufficient to meet the market needs. Despite technology advances, uncertainty abounds the supply side of the natural gas industry.

A recent development regarding FERC's ruling on the El Paso pipeline case which takes away the *full requirements* clause from its customers located in Arizona and New Mexico markets, will impact the infrastructure plans for the future. Since the customers can now contract with pipelines other than El Paso, the interest from the pipeline industry will grow significantly. We will see one or more new projects that will be completed in the future to satisfy not only the Arizona/New Mexico markets but also those in California. Increased interest in pipeline projects serving the Arizona/New Mexico markets such as the Coronado pipeline or the Pacific-Texas Pipeline will change the dynamics of gas supply to California. Further, projects such as El Paso's Ruby pipeline or Kinder Morgan's Silver Canyon pipeline will provide additional capacity to California.

## Natural Gas Transportation and Distribution System

The third component of the gas market analysis is the transportation and distribution system. Natural gas once produced from the wells has to be transported over long distances and distributed in the demand region to all consumers. As shown in **Figure 4-1**, each supply region is connected to one or more demand regions through one or more pipelines. The natural gas pipelines are well connected throughout the continent to form a flexible grid with multiple market hubs where gas is bought and sold by the producers, marketers, brokers and customers. The analysis includes the costs and capacities of pipelines represented as individual pipes or as a corridor of many pipes as appropriate. The detail on the transportation system assumed in the basecase is described in detail in the staff report *Natural Gas Market Assessment* (Publication number 100-03-006).

## California Natural Gas Storage

Natural gas, unlike electricity can be stored for short or long periods and can be injected when not in demand or withdrawn from storage when need arises. This provides an immense flexibility to the market in balancing supply and demand such that a stable and reliable supply is maintained. Also, the flexibility to store or withdraw gas helps to buffer volatile price movements in the market place.

Natural gas storage capacity is available throughout the US. During the last winter, natural gas prices were continually strained due to inadequate storage levels not in California but the rest of the U.S. Even though in-state storage was relatively healthy, high prices in the rest of the U.S. influenced the state's market.

In California, there are several storage facilities. The utility owned facilities support all of the core customer needs and provides some capacity that can be used by other customers. The only storage facilities in Southern California are those owned by the Southern California Gas Company. On the other hand, Northern California enjoys both private and public storage facilities. Expansion of the Wild Goose storage facility by the end of 2003 will provide enhanced benefits as early as the coming winter.

**Table 4-2** below shows the location of storage facilities in California. In Northern California, three companies own storage facilities. At the gas utility level, PG&E has three separate fields it uses to meet its customer's needs. Two more storage facilities are also located in Northern California with one field each. These two facilities, Wild Goose Storage and Lodi Gas Storage, are privately owned. The SoCalGas utility has four fields located in Southern California. Locations of each storage field are found in **Figure 4-4**. A fifth field, the Montebello Storage facility, owned by SoCalGas, was abandoned in 2002 and no longer provides any storage services, and is not indicated on the map. SDG&E has no storage facility in its territory, and depends totally on pipeline flows to meet the seasonal demand. However, SDG&E can use storage in the SoCalGas system to meet San Diego's needs.

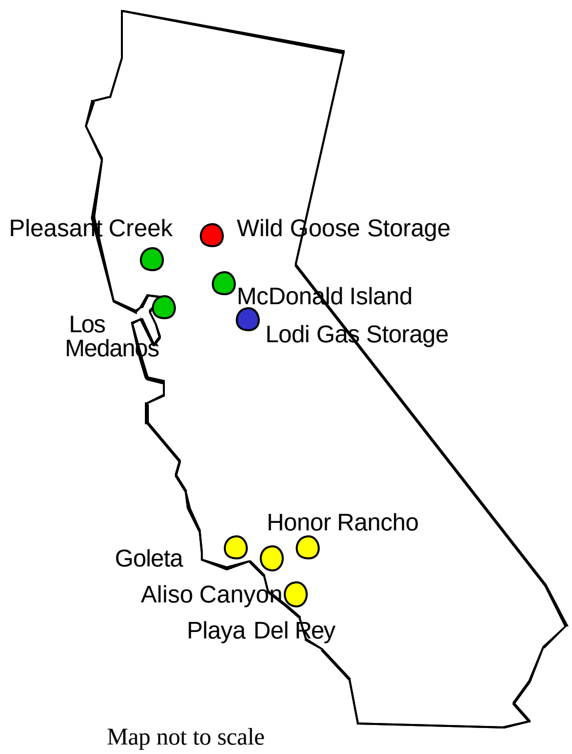
**Table 4-2**
**California Natural Gas Storage Facilities**

| Storage Facility Name | Working Gas Capacity (Bcf) | Maximum Withdrawal Capacity (MMcf/d) | Maximum Injection Capacity (MMcf/d) |
|---|---|---|---|
| PG&E | * 98 | 1,534 | 375 |
| SoCalGas | 120 | 3,200 | 800 |
| Wild Goose Storage [15] | 14 | 80 | 200 |
| Lodi Gas Storage | 12 | 500 | 400 |

* For the PG&E storage system, the 98 Bcf includes both cycling and non-cycling working gas capacity.

Natural gas is typically produced at a relatively steady pace over time while consumption of gas peaks in the winter when space-heating needs are high. Over the past few years in California, a second smaller peak in consumption has occurred when demand for gas-fired in power generation peaked during summer months. The balance between a steady production and varying demand is met mostly by storage systems. During times of low demand, usually in spring and fall seasons, natural gas from the pipelines is used to fill the storage facilities. During summer and winter seasons, both the pipelines and storage facilities are used to meet the demand peaks, with storage complementing any quantity demand in excess of what is supplied by the pipelines.

**Figure 4-4**
**Natural Gas Storage Facilities Map**




Hedging of natural gas prices is a second major advantage of storage for natural gas users who buy gas when prices are low and using it during peak periods when the prices are high. Likewise, gas suppliers can hedge their production by putting gas into storage when prices are lower and then sell the gas in the future when prices are better.

In general, natural gas storage complements short- and long-term needs. Core customers purchase a certain level of these storage services to meet peak winter space heating needs. A small portion of these services is allocated to the natural gas utility for pipeline balancing activities. The remainder is available for noncore customers, such as industrial users and electric generators to meet their variable consumption patterns and possible to hedge prices.

## Winter 2002-2003 Natural Gas Storage Use

On November 1, 2002 California entered the heating season with nearly 100 percent of its 243 Bcf of natural gas storage capacity filled. By the third week of March 2003, storage inventories reached a nadir, around 90 Bcf, because many storage customers withdrew gas from storage throughout the winter to avoid paying higher prices demanded by pipeline flows. The large draw down of California's natural gas storage this past winter surprised many observers, given that the Western U.S. experienced moderate-to-warm temperatures throughout the heating season. Since April 1, 2003, the beginning of the traditional storage injection season, California storage customers have made significant headway towards replenishing inventories bringing inventories to levels higher than what is normally required to meet the winter season needs

Storage levels, as of June 2003, are shown in **Figures 4-5** and **4-6** for Northern California and Southern California respectively. Northern California level includes PG&E, Wild Goose Storage, and Lodi Gas Storage inventories. The Southern California level represents gas in SoCalGas' storage fields. **Figure 4-7** shows the monthly trend in California's total storage inventory levels.

The rest of the nation experienced a more severe winter than the West. During the past winter and early spring, extreme cold temperatures in the eastern half of the continent forced the rapid depletion of natural gas storage inventories. **Figure 4-8** provides U.S. storage inventories through May 2003. Major concern is whether national gas storage levels, having reached record lows last April, can reach the desired level of around 3 trillion cubic feet by November 1, 2003. This challenge will be more pronounced if this summer is warmer than normal or if hurricanes disrupt natural gas production in the Gulf of Mexico.

There is a major concern with regard to making large storage injections over the coming months. Unregulated storage customers, such as power plant operators and large industrials make storage decisions based on their assessment of future market conditions. If customers expect that natural gas prices next winter will be cheaper than the current spot market prices, these customers might choose to defer gas purchases until next winter when they believe gas will be less costly, rather than store gas this summer. While this approach might be a sound business strategy for a private company to manage fuel costs, it provides little protection against tight natural gas supplies next winter.

**Figure 4-5**
**Northern California Storage Inventory**

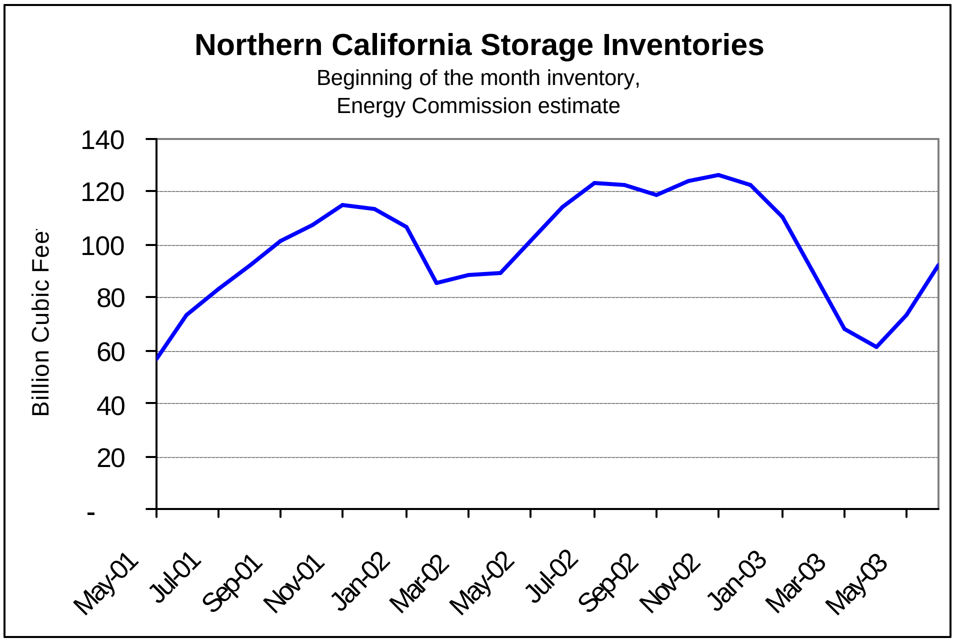



**Figure 4-6**
**Southern California Storage Inventory**

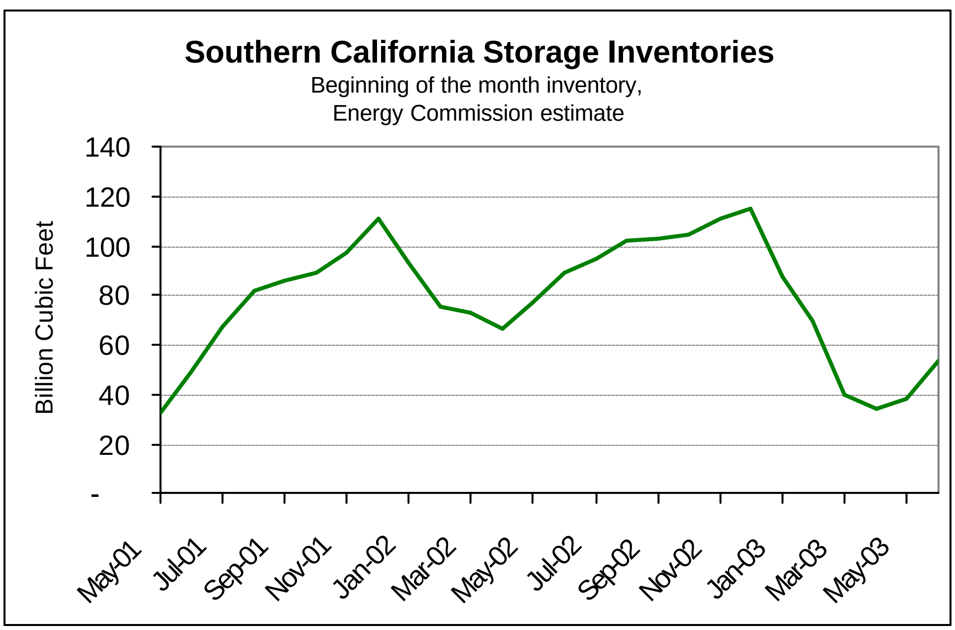


**Figure 4-7**
**California Storage Inventory**

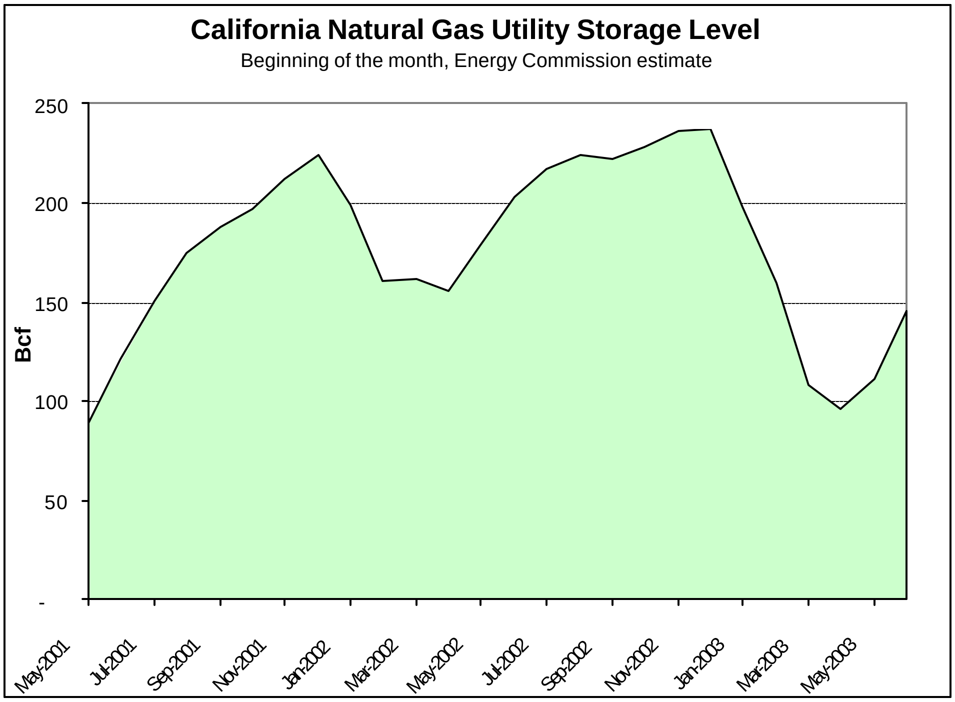
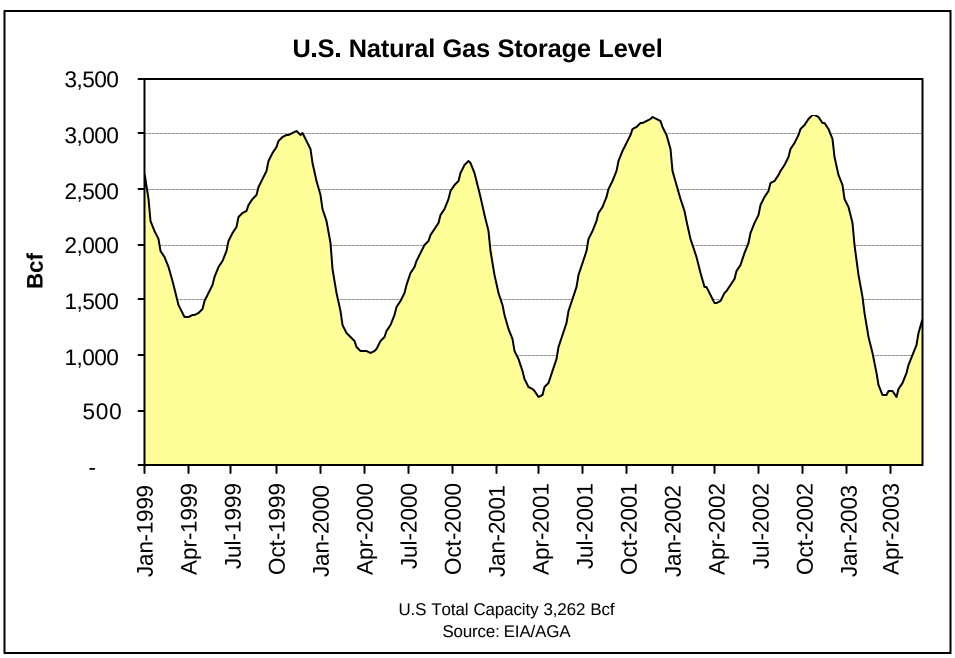



**Figure 4-8**
**U.S. Storage Inventory**

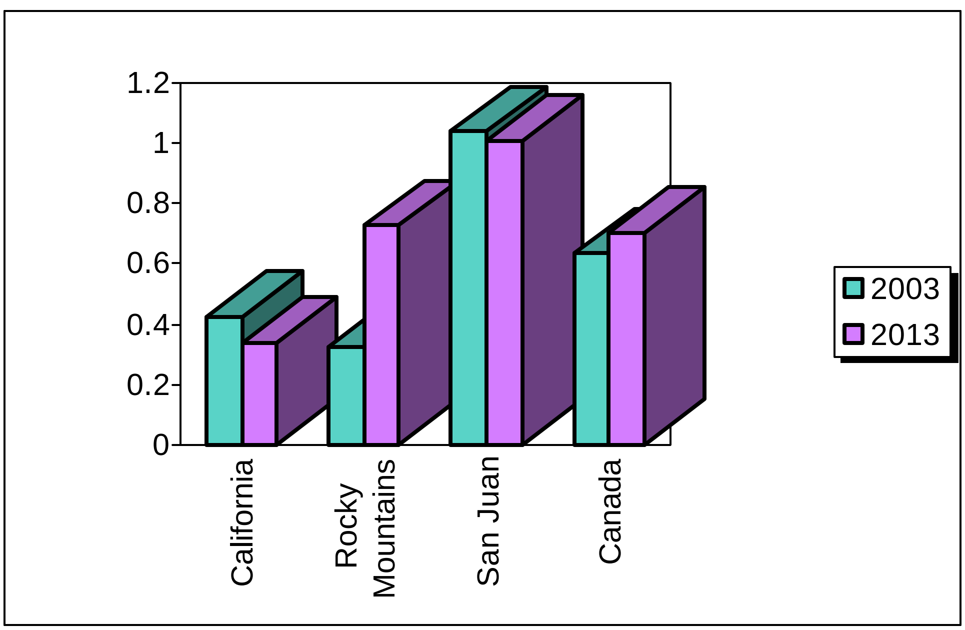


# Natural Gas Price and Supply in the Basecase Scenario

The competitive nature of the natural gas market has influenced not only the major industrial and power generation customers but also the residential and commercial customers. Natural gas bills have risen sharply, especially in the winter season when residential demand for natural gas is the greatest. This section discusses the long-term impacts and trends in natural gas markets including wellhead and border or city-gate prices in North America. The retail price projections for various market sectors or customer classes are discussed in Chapter 5. A primary finding is that increasing costs to find and produce natural gas to meet growing demand are driving natural gas prices to rise between 2003 and 2013.

California receives nearly 85 percent of its natural gas needs from outside the state. The three primary supply regions are the San Juan Basin, the Rocky Mountain Basin and the Western Canadian Sedimentary basin. **Figure 4-9** shows the sources for natural gas in California during this year and the project sources in 2013. The Rocky Mountain region is a relatively new supply basin compared to other supply basins in the U.S. The prices in this region have been low when natural gas prices in the rest of the nation had been very high due to a lack of transportation pipeline capacity out of the Rocky Mountain Basin. Recent expansion of the Kern River pipeline (in May 2003), demonstrates the importance of this supply source for California, and supplies coming from the Rocky Mountain region will be doubling over this time period.

**Figure 4-9**
**Projected Natural Gas Supplies**
**for California (in Tcf/yr)**

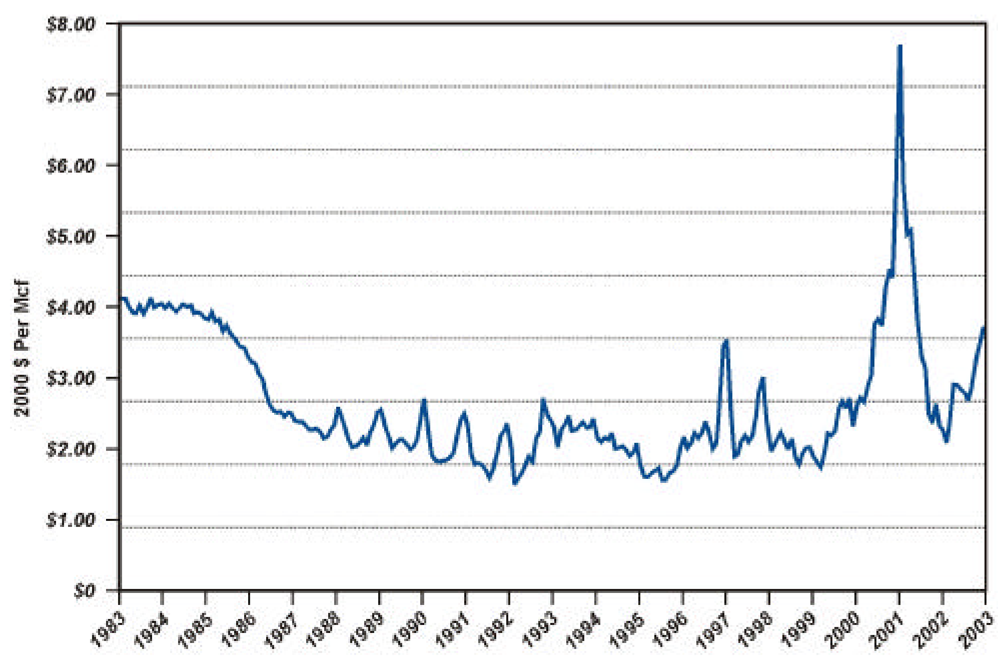


As shown in the **Figure 4-9**, supplies from in-State production and from the southwest basins (i.e., San Juan and Permian Basins) are expected to remain relatively flat. Forecasted Canadian production will occupy a larger share of California's consumption, reaching 0.7 Tcf/yr by 2013. Supplies from the Rocky Mountain and Canadian basins provide the incremental growth in gas demand. The Rocky Mountain Basin shows the highest growth rate in production.

## Wellhead Prices in North America

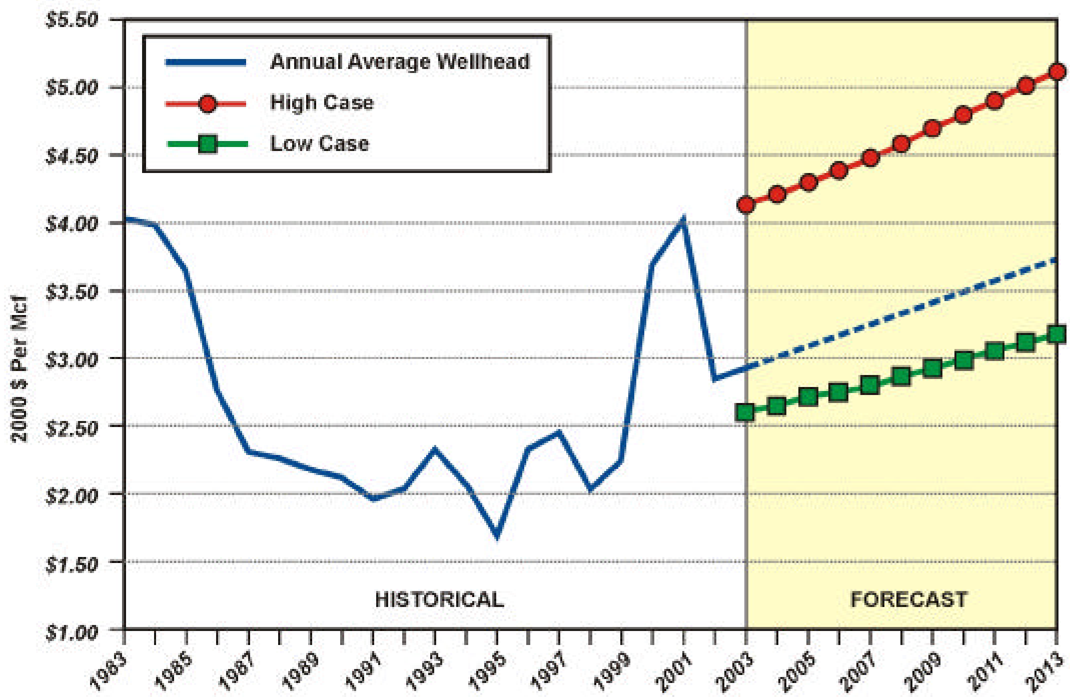
Wellhead prices reflect the capital and production costs of natural gas and the willingness of buyers to pay for it. These prices motivate gas producers to explore, drill, develop, and produce the gas needed to satisfy consumer demand. Reduced price control at the wellhead in the United States and Canada caused natural gas supplies to increase, surpassing total natural gas demand from the mid-1980s to the late-1990s, which resulted in a reduction in natural gas prices. **Figure 4-10** shows the historical trends in monthly wellhead prices while **Figure 4-11** illustrates the historical path of annual average wellhead prices in the Lower 48 States along with the projections under the basecase scenario for the years 2003 to 2013. Also shown in **Figure 4-11**, are results of two scenarios describing the upper and lower bounds for natural gas prices. These bounding scenarios represent plausible but not sustainable trends indicating the range over which gas prices can move up or down, depending on market conditions, over the future years between 2003 and 2013.

**Figure 4-10**
**Historical Wellhead Prices in the Lower 48 States –Monthly Averages**




Source: EIA

**Figure 4-11**
**Historical and Projected Wellhead Prices in the Lower 48 States with High and Low Boundaries – Annual Averages**




Source: EIA (Historical Data) and the California Energy Commission (Forecast)

**Table 4-3** gives the projected prices, in year 2000 dollars per Mcf, for major gas-producing regions throughout North America. The differences in wellhead prices between regions stem from dissimilar regional demand growth, varying resource costs, differences in access to production basins, and available pipeline capacity.

Wellhead prices in the San Juan Basin, Rocky Mountain Basin, and Alberta are especially of interest to California because they are expected to provide nearly 85 percent of natural gas consumed in the state. Wellhead prices for Canadian gas supplies will likely be less than those in the Lower 48 States, but prices from both sources are expected to increase by more than two percent annually. The 2013 weighted-average price for Canadian wellhead gas is projected to be $3.12 per Mcf, compared to $2.49 in 2003. By 2013, the lowest-cost production regions in the Lower 48 States will most likely be the Rocky Mountains, the San Juan Basin in the Four Corners region, and the Northern Great Plains Basin in Montana. In 2013, all three production regions will have wellhead prices below the weighted-average price for the Lower 48 States of $3.71 per Mcf.

**Table 4-3**
**Projected Wellhead Prices – Annual Averages (2000$ per Mcf)**

| Producing Region | 2003 | Projected 2008 | Projected 2013 |
|---|---|---|---|
| **Lower 48 States** | | | |
| Anadarko | 3.14 | 3.57 | 4.04 |
| Appalachia | 3.55 | 3.91 | 4.19 |
| California | 3.16 | 3.56 | 3.89 |
| Gulf Coast | 3.04 | 3.42 | 3.82 |
| North Central | 3.22 | 3.54 | 3.83 |
| Northern Great Plains | 2.57 | 2.78 | 2.95 |
| Permian | 3.04 | 3.44 | 3.85 |
| Rocky Mountains | 2.73 | 2.96 | 3.20 |
| San Juan | 2.76 | 3.12 | 3.46 |
| **Weighted Average: Lower 48** | **3.02** | **3.34** | **3.71** |
| **Canada** | | | |
| British Columbia | 2.65 | 3.05 | 3.41 |
| Alberta | 2.41 | 2.73 | 3.02 |
| Saskatchewan | 3.22 | 3.76 | 4.14 |
| Eastern Canada | 3.72 | 3.64 | 3.88 |
| **Weighted Average: Canada** | **2.49** | **2.82** | **3.12** |

Source: California Energy Commission

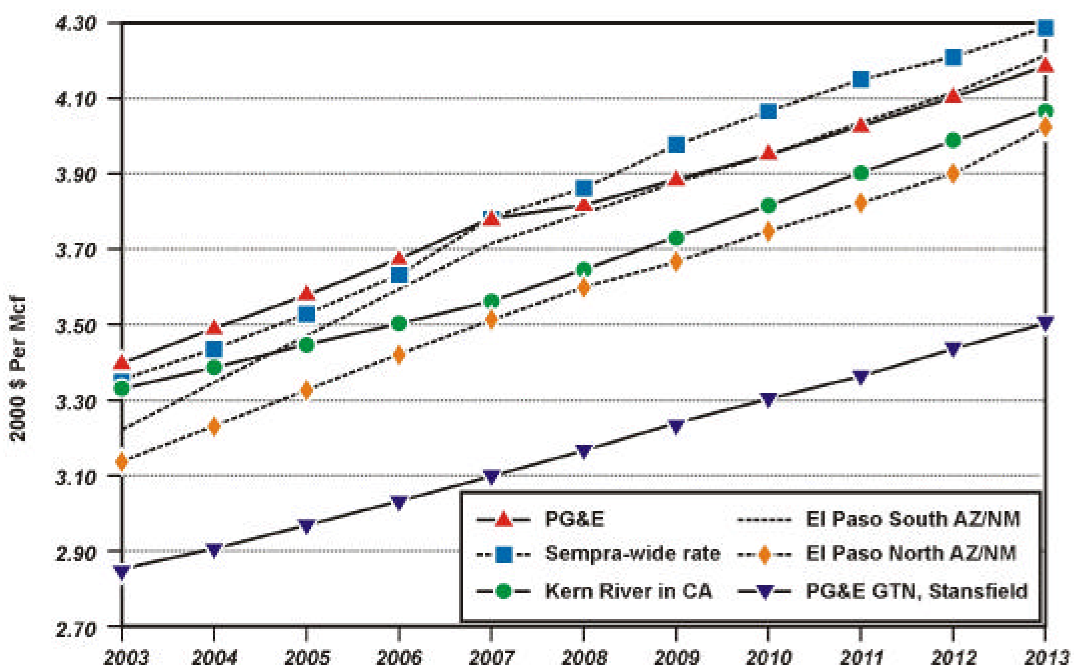
Prices for gas produced in the Lower 48 States are expected to increase 2.1 percent per year, climbing from $3.02 in 2003 to $3.71 per Mcf in 2013. Canadian wellhead prices will likely increase 2.2 percent per year, from $2.49 in 2003 to $3.12 per Mcf in 2013.

Low wellhead prices and easy access to affordably priced natural gas along interstate pipelines are attractive to gas-fired electricity power generators. **Figure 4-12** shows the price projections for electricity generators located within the WECC region. Buying gas directly from interstate pipelines allows gas customers to avoid gas-utility distribution costs, associated taxes, and surcharges. Other costs or constraints, however, may be incurred by locating a power plant near an interstate pipeline. Saving on gas costs is particularly important to merchant generators who compete for market share based on their electricity prices. Other factors that power plant developers consider include proximity to electricity transmission systems and costs to connect to it, including congestion costs.

Electricity generators who receive large gas shipments from in-state utility-owned gas lines are classified as noncore customers in the PG&E, SoCal Gas, and SDG&E gas utility systems. They purchase gas supplies from third parties. It is projected that the electricity generators located in California will probably pay higher natural gas prices, approximately two percent above inflation annually. As noncore customers in the utility systems, these electricity generators will be paying higher prices for gas compared to electricity generators taking gas directly from interstate pipelines. Electricity generators located near California demand centers, however, may be offsetting these higher gas prices by reducing other expenses, such as transmission line losses and costs.

Electricity generators receiving gas from PG&E will pay about the same price as electricity generators in Southern California. Commodity prices will be lower in PG&E's service area, but these are partially offset by higher transportation costs that eventually become cheaper over time. PG&E is likely to attain a slight price advantage over Southern California after 2006.

**Figure 4-12**
**Projected Natural Gas Prices for Electricity Generators within the WECC Region**




Source: California Energy Commission

The lowest-cost for natural gas is, and will continue to be, Canadian gas via the PG&E Gas Transmission Northwest (GTN) interstate pipeline at the Washington-Oregon border in Stanfield, Oregon.

The Rocky Mountain basin is another supply basin that has experienced extremely low prices over past few years due to pipeline constraints. With the expansion of the Kern River pipeline, California will get a significant share of its needs from this region, thus moderating the price volatility in the state. Kern River will be able to provide increased supplies to both Northern and Southern California.

In Arizona, electricity generators will probably see a slight price advantage through 2013 for gas delivered using the northern El Paso pipeline corridor – a corridor that includes El Paso, Transwestern, and Southern Trails pipeline systems – rather than the southern El Paso corridor. The major advantage comes from easier access to low-priced San Juan Basin gas compared to gas from the Permian and Anadarko Basins. Since much of the new, electricity generation capacity appears to prefer locations along the northern El Paso pipeline corridor, the necessary pipeline infrastructure improvements would add costs to these prices.

## Relative Costs of Pipelines and Transmission Lines

The relative costs of gas and electric transmission infrastructures affects where market participants propose to build power plants. Rough cost estimates suggest that new gas pipelines are cheaper than new electric transmission lines – in other words, moving fuel is cheaper than moving power. For construction in favorable terrain, a capital investment of $300 million will produce:

- About 100 miles of 500 kV AC electric transmission line that can transmit about 1,500 MW. The line can bring about 36,000 MWh per day to the electricity demand center.
- About 100-125 miles of 36 inch natural gas pipeline that can carry 1 billion cubic feet per day. That much gas, burned in modern combined-cycle power plants at 7,200 Btu/kWh, can generate about 140,000 MWh per day at the electricity demand center.

In operation, natural gas pipelines are more efficient. Electricity loss on the 100 mile electric transmission line would be .6 to .8 percent, whereas, gas consumption at compressor stations ("shrinkage") to move gas through a 100 mile gas pipeline would be about .2 to .3 percent. Finally, underground gas storage in consuming regions allows gas pipelines to be used at high utilization rates; by contrast, transmitted electricity must generally be used in real time.

If the prices for shipping gas and electricity reflect the underlying capital and operating costs, many of the gas-fired power plants needed to serve California's electricity demand growth would be built in California. To date, FERC policy has caused the costs of transmission projects to be borne directly by consumers, not generators. If this policy remains in effect, developers will tend to site power plants near gas supply basins, rather than within California. FERC is also considering elimination of export fees, which will further encourage remote siting of power plants.

## Additional Natural Gas Market Scenarios

The basecase assessment described in the previous section represents the best estimate of the behavior of the natural gas market over the next ten years. This assessment uses a specific set of assumptions about demand, natural gas resources, transportation rates, and pipeline capacities. Many of the input parameters included in the assessment have uncertainty tied to them. The observed volatility and sudden spikes or troughs indicate this uncertainty in market prices and supply availability. One way to include the assessment of uncertainties in the market place is to conduct scenarios and sensitivities to test the impact of one or more variables on the assessed price and supply availability. A detailed description of the scenario inputs, assumptions and results is included in the ***Natural Gas Market Assessment Report*** (Publication number 100-03-006). The scenarios studied can be generally classified under supply or demand based market changes.

The assumptions in each of the scenarios are briefly noted below:

1. Low Economic Growth Scenario: The recovery forecasted in the Baseline in 2004 is delayed by one to two years so that growth on average is about 1 percent lower than the baseline economic forecast. This scenario assumes lower growth in all sectors of gas demand.

2. High Economic Growth Scenario: This scenario assumes a more robust economy with a stronger recovery than forecasted in the Baseline Scenario. Based on employment data for the last twenty years, the economic drivers for the sector forecasts are accelerated by 1-2 years to achieve an annual growth of about 1 percent higher than in the Baseline, for the years 2004-2007. Demand changes occur in all sectors under this scenario.

3. Dry Hydro Scenario: Natural gas demand assuming dry instead of average hydro conditions. This scenario reflects increases in gas demand in the electricity generation sector with the same capacity expansion plan as in the Baseline Scenario. The core and noncore demand projections remain unchanged as compared to the basecase.

4. Lower PGC Impacts Scenario: Natural gas demand assuming no utility DSM spending after 2003 and only 100 MW per year new renewable generation. It reflects UEG gas demand of a capacity expansion plan with more gas-fired resources than in Baseline Scenario.

5. Higher PGC Impacts Scenario: Natural gas demand assuming a doubling of PGC funding for DSM and an increase to 600 MW per year of new renewable generation. It reflects UEG gas demand of a capacity expansion plan with less gas-fired resources than in Baseline Scenario.

6. Low Gas Supply Scenario: Given the many views about the

## Integrated Price and Supply Outlook

*Unlike scenarios that investigate impacts of individual parameters, natural gas markets do not experience variations in their fundamental drivers one at a time.* Two integrated scenarios including simultaneous changes of several parameters in the model were studied. Critical input variables--natural gas resource potential, LNG availability, natural gas demand projections and the availability of alternative fuels competing with natural gas for market share formed the basis of the parameter changes.

*What would happen if events associated with model input assumptions simultaneously occurred?* The selection of the range of input parameters is intended to provide the boundaries for natural gas price in the market under the Integrated Price and Supply Outlook scenarios. Thus, the high and low price cases illustrate the possible extremes of annual average natural gas prices over the forecast horizon. These extreme price levels are achievable on a short-term basis, but, they are not sustainable over a longer duration. The interaction of market forces and response to high or low prices would tend to push supply and demand away from the extremes and toward the more plausible basecase.

difficulty in finding new resources combined with many projections suggesting tight or insufficient gas production to meet growing demand, this scenario attempts to limit the availability of supplies in the market. This is accomplished by lowering the 'reserve appreciation' factor, which leads to a rise in the cost of natural gas at the wellhead. This scenario investigates the impact of low resource availability on gas supply and the ability and extent to which the market will switch to other alternative fuels in response to higher natural gas price.

7. Increased Vehicle Transportation use Scenario: Natural gas demand can increase significantly with the expectation that Fuel cells will play a major role in auto industry. Further, clean air initiatives could increase demand for LNG and CNG vehicles. This scenario assumes that vehicles equipped with fuel cells using hydrogen, generated from natural gas will increase significantly by the year 2015, reaching nearly 5 to 10 percent of the total gas consumed in the state.

8. Large Quantity of LNG to CA Scenario: Liquefied natural gas or LNG is a premium fuel, globally traded, available in large quantities at reasonable prices in many countries around the world. High natural gas prices in California have raised the interest in importing LNG supplies along the western coast of U.S. This scenario considers the potential impacts of building one or more terminals in California and Baja Mexico. LNG terminals are assumed to be built at Humboldt Bay in Northern California, Los Angeles or Long Beach in Southern California and along the coast in the northern part of Baja California, Mexico. The terminal specifications are based on currently proposed LNG projects.

9. Integrated High and Low Gas Price Scenarios: As mentioned earlier, the high and low gas price cases provide a boundary to higher or lower prices that could be achieved by the gas market. These integrated scenarios make assumptions on various factors or outcomes that tend to either raise or lower prices. **Table 4-4** summarizes the input assumptions in the integrated scenarios.

# Results for Natural Gas Market Scenarios

## Integrated High and Low Gas Price Scenarios:

**Figure 4-13** shows the price trends in the Integrated High and Low Gas Price scenarios and compares them to the basecase projections. In the High Price scenario, prices climb from $4.12 per MCF in 2003 to $5.12 per MCF in 2013. Prices in this scenario experience an annual growth rate of 2.2 percent. On the other hand, the Low Price scenario demonstrates a slightly lower growth rate, climbing at 1.98 percent. Prices in the Low Price scenario grow from $2.56 per MCF in 2003 to $3.11 in 2013.

In the Low Price scenario, Lower 48 production reaches 22.6 TCF in 2012, whereas, in the High Price scenario, production grows to 26.8 TCF. The higher production results from the severe environmental constraints that lead to natural gas being the primary fuel of choice throughout the US. As shown in **Figure 4-14,** the production of natural gas in the lower 48 states increases in both scenarios when compared to the basecase. The increase in production of natural gas in the Low Price case is due to the fact that as natural gas prices drop, fuel switching in specific regions of the US tends to use more natural gas than that used in the basecase. **Table 4-5** tabulates the price growth rates and compares them with the rate of the basecase.

**Table 4-4**
**Integrated Price and Supply Assessment Assumptions**

| Parameters | High Price Outlook | Basecase Projection | Low Price Outlook |
|---|---|---|---|
| **Natural Gas Resources** | | | |
| Reserve Appreciation | Lowered by 25%. | Appreciation range: 0.03% to 2.2 %. | Raised by 33%. |
| Gas Resources | Land Access: 11% land restrictions in Rocky Mountains | Lower 48: 975 Tcf<br>Canada: 417 Tcf | Same as basecase. |
| **Liquefied Natural Gas** | | | |
| Liquefied Natural Gas | Same as basecase | Four facilities operating | Three facilities added: NorCal, SoCal, Baja |
| **Natural Gas Demand** | | | |
| Gas Demand | Low efficiency improvements. Step increase in gas demand, up 10% by 2017. 5% comes from demand in transportation sector. | Total US consumption by 2007: 23.99 Tcf. | High efficiency improvements. More total usage offset efficiency gains. |
| **Competing Fuel Sources** | | | |
| Oil Price | World oil prices rise to $35 per barrel by 2007, thereafter | World oil prices rise to $26 per barrel by 2007, then remain constant through forecast horizon. | Same as basecase. |
| Oil Burn | All states are constrained from switching to oil, by 2007 | Switching allowed in four North American regions. | Same as basecase. |

**Figure 4-13**
**Annual Average Lower 48 States' Wellhead Price ($/MCF)**

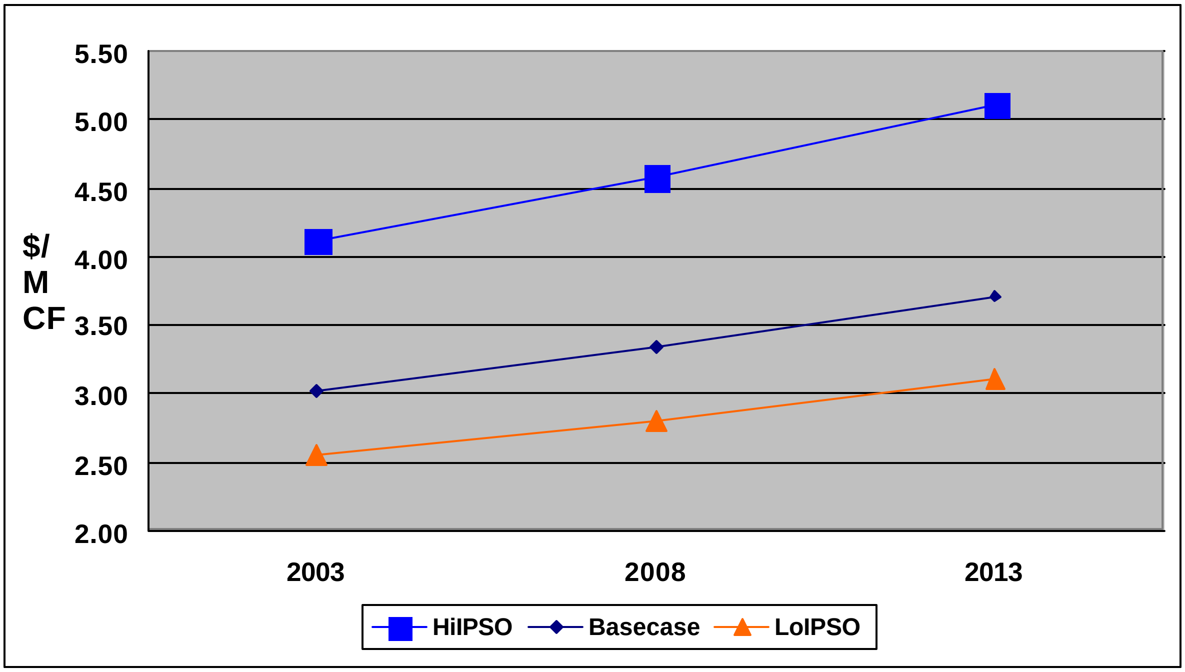



**Figure 4-14**
**Natural Gas Production in US (TCF per year)**

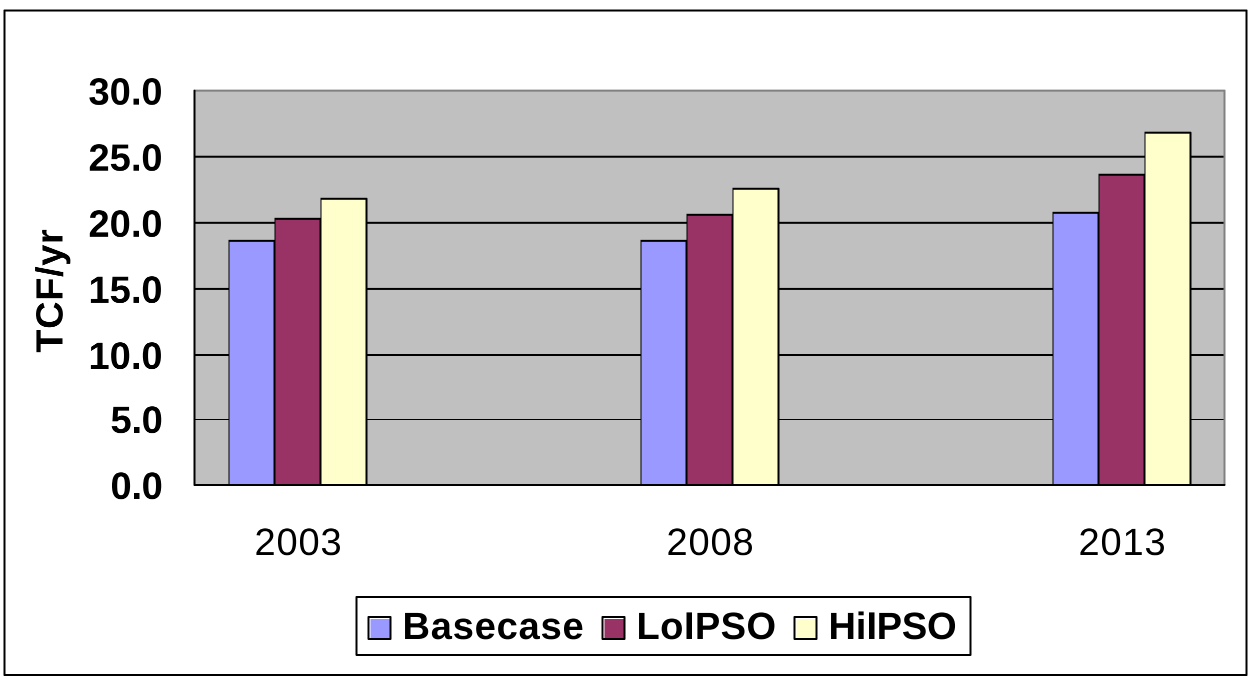


**Table 4-5**
**Annual Price Growth Rate, %**

| | |
|---|---|
| Low Price Scenario | 1.98 |
| Basecase Scenario | 2.08 |
| High Price scenario | 2.19 |

## Demand Scenarios

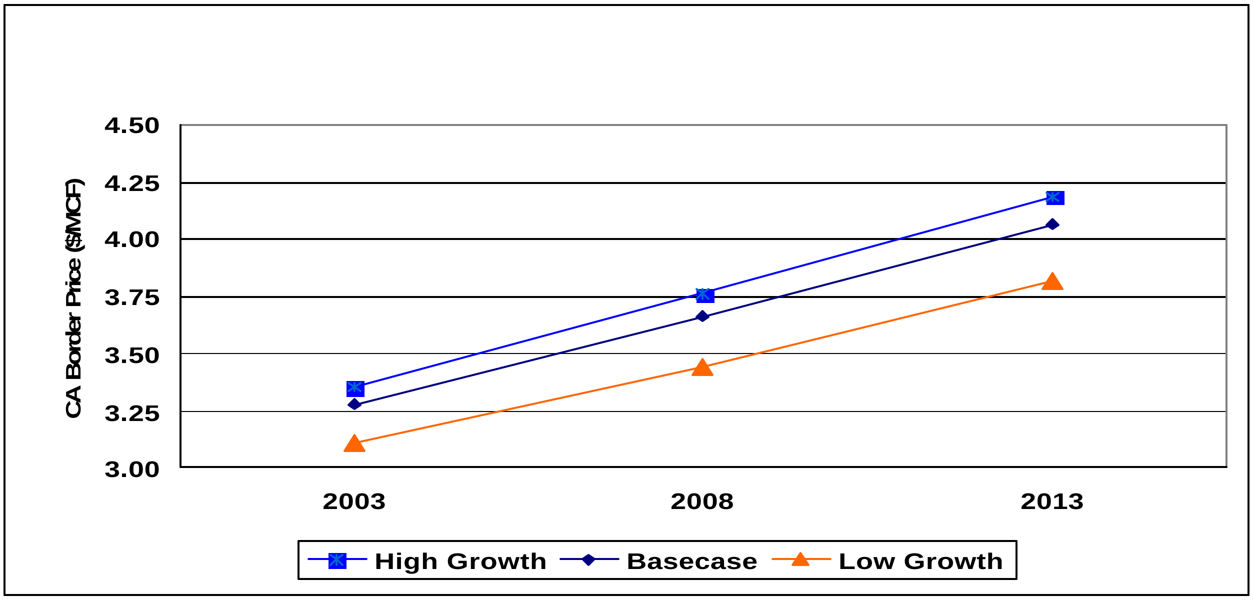
Overall, the demand scenarios indicate that changes in natural gas demand, due to factors such as low hydro-generation due to drought conditions or moderate slowing or speeding up of the state's economy, do not appear to affect the long-term trends in the natural gas market. Also, the Economic Growth and Public Goods Charge Impacts scenarios indicate that the impacts on price and supply of natural gas are not very significant from a long-term perspective. However, the growth and efficiency factors, when addressed from a short-term or seasonal perspective can and will impact markets.

The economic growth and PGC impact scenarios result in either lowering or increasing the demand for natural gas. The Low Economic Growth or High PGC Impact scenario assumes that the core and noncore demand is reduced by 2.5 percent while the gas demand for all power generation in the US drops by 9 percent. The High-Economic Growth and Low PGC Impact scenarios both assume an increase in gas demand of 2.6 percent in the core and noncore sectors and a 7.4 percent increase in the power generation in the US.

The total change in annual gas demand for the Power generation sector in California in these scenarios is not very significant compared to the total gas demand in California. The low PGC Impact or the high growth scenario does not increase the gas demand significantly enough to raise gas prices. By 2013, the price increases by about 2.7 percent above the basecase prices.

On the other hand, the High PGC Impact or Low Economic Growth scenarios result in lowering the gas demand across all sectors and the price drop in this case is about 7 percent lower than basecase prices. **Figure 4-15** compares the California border prices in the high and low growth cases with basecase price projections.

**Figure 4-15**
**California Border Gas Price**
**for the High/Low Economic Growth and PGC Impact Cases**



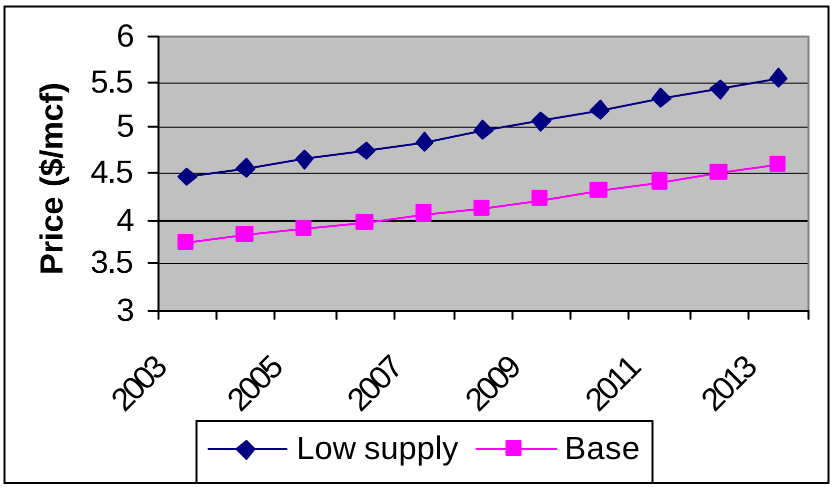

## Low Gas Supply Scenarios

The uncertainty in availability of resources has been a prominent issue in North America. Discussions indicate that the production life of the majority of natural gas fields in the US and Canada have matured and that natural gas production in the US will begin to decline within the time frame analyzed in this assessment. In fact, the industry view, regarding potential supply sources that can be produced, is that supplies will be tight over a longer term and that it will cost more to find and produce the natural gas to meet the growing demand. The contrary view is that the new and unconventional resources which exist in abundance can economically be developed and explored. These unconventional resources refer to the coal bed methane deposits, shale and tar sands in the US and Alberta.

Assuming a restricted resource base, the market needs will be met by more expensive gas resources and the cost to access these resources increase over time at a faster rate than assumed in the basecase. Annual average wellhead prices in the US increase by about 25 percent above basecase values over the next 10 years. The wellhead prices rise by about $0.60 to $3.60 per MCF in 2003. By the end of the forecast horizon, wellhead prices rise to $4.40 per MCF by 2013. With regard to supplies to California, market shares of Canada and domestic production do not change significantly while the loss in market share for the Southwest region is offset by increasing supplies from the Rocky Mountain region. The San Juan Basin, being a more mature basin, loses its market share to the relative new Rocky Mountain Region. California's statewide average price rises by nearly $1.00 per Mcf by the year 2013.

As a result of increasing wellhead prices there is an increase in fuel switching from natural gas to alternative fuels in the four regions where fuel switching is assumed to occur (Mid Atlantic, South Atlantic, West North Central and the West South Central census regions. **Figure 4-16** shows the US wide annual average natural gas price paid by the power generation sector under basecase assumptions and compared with the Low Gas Supply scenario. As shown, if natural gas supplies do not materialize as anticipated in the basecase assumptions, power generation prices will increase by about 20 percent above the basecase, over the assessment period.

**Figure 4-16**
**Impact of Low Gas Resources on US Wide Gas Price**




## Liquefied Natural Gas facilities on the U.S. West Coast Scenarios

The potential for large quantities of LNG to supply California, Baja California and the Southwest Desert markets is gaining prominence. In fact, several companies have put forward proposals to build LNG facilities along the US and Mexico's West Coast. LNG brought in to serve California markets would be on way to meet the growing demand for natural gas.

This scenario examines the impact of building three LNG facilities on the West Coast: one in Northern California, one in Southern California, and the third in Baja

**LNG - A Global Resource**

One of the most controversial topics being currently discussed is the potential to increase the amount of liquefied natural gas (LNG) that can be imported into the U.S. Global resources are plentiful and are available from multiple countries. The Gulf and Eastern U.S. seaboard has been importing LNG for more than 20 years. Of the four terminals, three of them are currently operating with the fourth slated to come on-line in August 2003. A number of new projects are being pursued to increase the quantity of LNG imports. There are several projects being proposed along the U.S. West Coast. California is a growing state demanding more natural gas to satisfy all classes of customers. Being at the end of the pipelines, California has little control on the amount of natural gas that can be brought in by pipelines. There would be benefits to finding a fourth supply source in addition to the San Juan, Rocky Mountain and Canadian sources that have historically supplied gas to the state. Thus significant efforts are now underway to build and supply California with LNG from a variety of sources including the Indonesia, Bolivia, Peru, Australia. Russia and Alaska.

California, Mexico. While there are no final decisions to locate the LNG facilities at these locations, this scenario attempts to capture the infrastructure impacts on California and neighboring states if the LNG facilities are indeed permitted and constructed, and bring significant quantities of LNG into the Western States. This scenario also assumes that the North Baja Pipeline reverses its flow directions and takes the LNG supplies from Baja, Mexico to Ehrenberg AZ, where it interconnects with the El Paso's Southern pipeline system serving the Southwest Desert region, the Southern California Gas Company's backbone pipeline to serve Southern California markets, and the El Paso's bi-directional Lateral pipeline inside California. (North Baja pipeline currently serves markets in Baja California with gas supplies from the CA/AZ border point at Ehrenberg, AZ).

The basis for choosing these three locations for LNG facilities is that there are one or more proposals active in each of the three locations. Several scenarios were conducted with varying assumptions on the LNG facility location. One of the scenarios attempts to evaluate the impact of costs for landed LNG on the West Coast to ensure that the assumed three facilities operate at relatively high load factors.

**Figures 4-17 and 4-18** compare potential LNG imports into the US under various scenarios. The projections for LNG imports on the West Coast assume that facilities will be built and operational by 2007 or 2008. Further, since the assumption in the analysis of the LNG scenario was to study impacts of LNG flowing into the Western States on natural gas pipeline infrastructure, the price at which LNG can come into the West Coast market was adjusted lower to accommodate the higher flows.

**Figure 4-17**
**LNG Imports Along US West Coast**

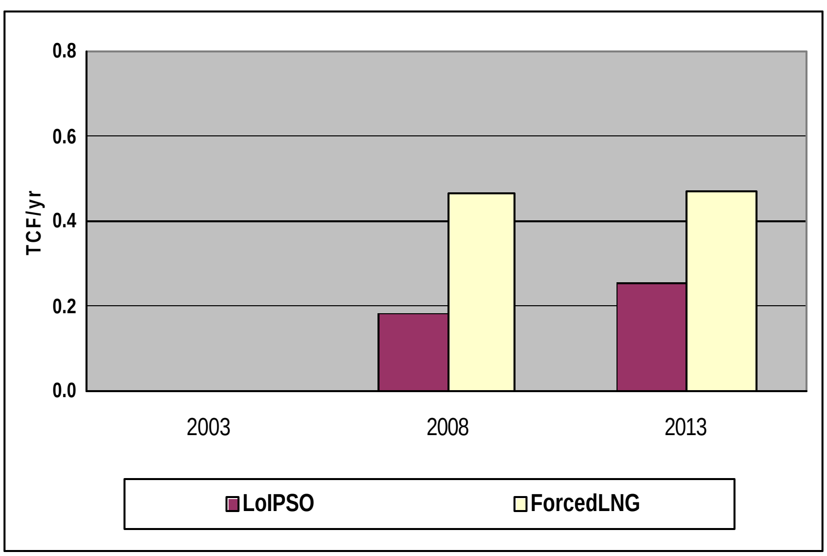
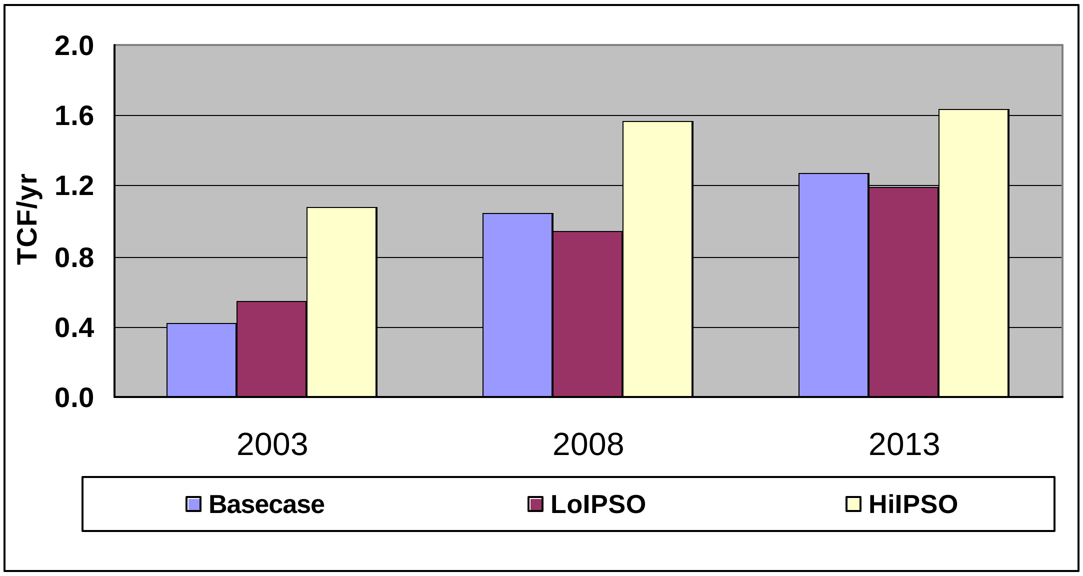


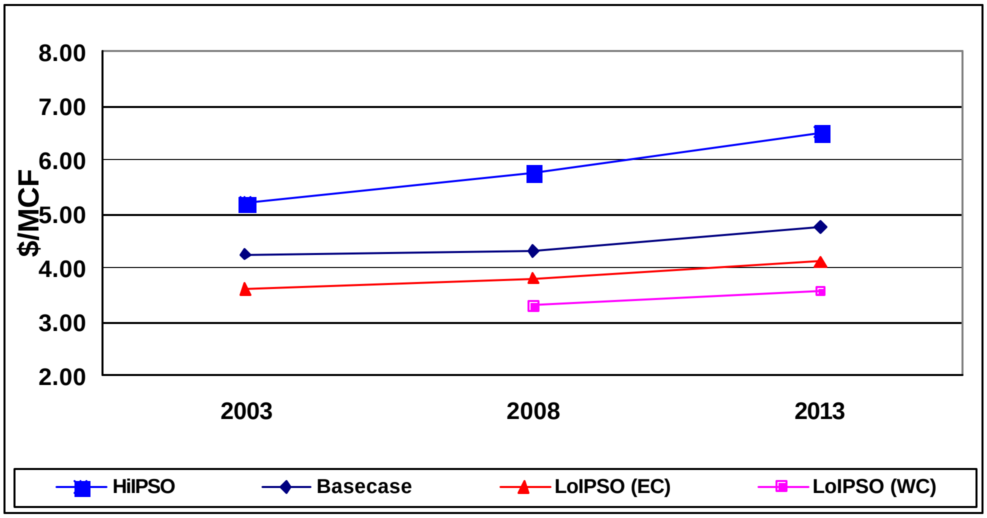
**Figure 4-18**
**LNG Imports along US Gulf and East Coast**




The East Coast continues to import LNG under all scenarios. LNG continues to be an economic option under the High Integrated Gas Price Scenario, with imports rising throughout the assessment period to satisfy the increasing demand. The Low Integrated Gas Price Scenario also sees a growing demand over time for LNG, although imports are slightly less than those in the basecase. In the Low Gas Price Scenario, natural gas prices in the US drop significantly to be competitive with the LNG import prices. On the West Coast, one LNG Scenario was designed to provide large quantities of LNG at the three potential terminals.

**Figure 4-19** shows prices of LNG on the East Coast for the Basecase and the two Integrated Gas Price scenarios. The Figure also shows the price of LNG on the West Coast in the Low Integrated Gas Price Scenario.

**Figure 4-19**
**Annual Average Price for LNG Imports**




# Differences Between Scenarios and Short-Term Markets

This section discussed multiple scenarios that could result from various actions taken by governments, industry, utility and end-use groups over the next 10 years and more. The actions and behavior of the market players will significantly impact the natural gas market. For the most part, this analysis has focused on long-term implications and trends over the next ten-year period. The scenarios highlight implications of market fundamentals and provide critical information to decision-makers from the perspective of need and planning on capital intensive projects such as new pipelines, LNG terminals and storage facilities.

Uncertainties and risk exist in both the short-term markets and in the long-term trend assessment. Such uncertainties in the market place will place stress on the supply/demand equilibrium that can result in price shifts over long-term trends or spikes in short-term analysis. While supply and demand will come into equilibrium at all times, short-term imbalances will occur, especially during peak days when the system capacity will be stressed beyond its capacity.

Major short-term concerns in the gas industry include natural gas production levels, related drilling activities, pipeline slack capacity and utilization, and use of storage to buffer swings in supply and demand imbalances during seasonal and peaking market conditions. Analysis of these issues requires the Energy Commission to focus on short-term market fundamentals requiring monthly or even daily time periods as opposed to the current annualized analysis.

# Additional Analytical Needs on Gas Storage

The Energy Commission recognizes the need to conduct a comprehensive analysis of short-term energy trends to complement its long-term energy forecasting work. A joint effort between the Energy Commission and University of California, Davis (UC, Davis) has been established to develop a monthly short term analysis and model simulation to study California's natural gas network. The objective of this effort is to understand the role of storage. This work will entail viewing regional storage issues integrated with the electricity market needs for natural gas.

Preliminary development of the analytical tools have provided the following insights:

- A major factor in storage activity is the cost of transporting and storing gas or of utilizing pipeline supplies during peak demand periods.
- There is an optimal combination of pipeline and storage capacity. Generally, storing gas becomes more valuable as pipelines become more congested.
- Flexibility in the pipeline and storage systems is important. For instance, storage becomes less critical if the amount of gas flowing through pipelines can be altered in a short time.
- Short-term price spikes are a result of combined inflexibility of demand and supply.
- The ability to store gas may reduce price variability and annual average gas price. Also, storage smoothes the pattern of pipeline flows and of the corresponding transportation costs.

These insights bring up several policy questions that the Energy Commission and UC Davis will continue to investigate:

1. Is there a need for additional storage capacity, including working gas, withdrawal, or injection capacities?
2. Would transmission and storage pricing mechanisms that more closely track operating costs contribute to a more efficient operation of the existing infrastructure?
3. Has the injection and withdrawal pattern changed as gas-fired electricity generation demand has increased, especially during the summer months?

# Conclusions

**Market Conditions**: Between 2003 and 2013, annual average supplies of natural gas will be sufficient but more costly. With the increase in demand for natural gas throughout North America, supplies at cheap prices are not as plentiful as expected earlier. The number of supply basins that are able to produce sufficient quantities of gas will decline over time, increasing the need for infrastructure to transport natural gas from a limited number of supply basins to various demand regions. As a consequence, the U.S. will likely become increasingly reliant on natural gas from Canadian and liquefied natural gas imports, while continuing to develop the domestic "unconventional" sources of natural gas to meet growing demand. Under tight supply conditions, some customers might get priced out of the natural gas market, leading to "demand destruction".

In some regions of the U.S., industrial and power generation customers with dual-fuel capability will likely switch to another fuel, such as distillates or residual oil during high natural gas price conditions. However, no appreciable level of switching to any coal or oil derived fuels can occur in California.

Natural gas infrastructure has a strong impact on price and supply availability in each demand region. New gas-fired power plants in the Western U.S. are increasing gas demand and, in turn, triggering the need for new investments in interstate pipeline projects. The gas flow patterns in the basecase indicate that additional pipeline capacity will be needed to meet growing electricity generator demand in southern Nevada, Arizona, and New Mexico. The San Juan and Rocky Mountain basins will be the primary supply basins of choice. Also, the anticipated increase in production in the Rocky Mountain basin depends on additional pipeline capacity to move the gas to various markets.

**Projects Completed**: Within California, analysis shows that in addition to the 180 mmcfd capacity added in 2002 at Malin, Oregon, PG&E will need additional receiving capacity or storage after 2006. SoCal Gas completed major infrastructure projects with a total pipeline capacity addition of 375 million cubic feet per day. As a result, under average conditions, SoCal Gas has adequate intrastate slack capacity for its service territory through 2013.

**New Pipelines**: Projects anticipated to supply the state's growing thirst for natural gas include El Paso's Ruby Pipeline and Kinder Morgan's Silver Canyon pipeline. Ruby pipeline increases access to the Rocky Mountain region while the Silver Canyon provides access to both the Rocky Mountain and the San Juan basins.

**LNG**: Being at the end of the pipeline systems, California needs access to a new supply source that can compete with the existing sources. The potential to import LNG into California will have a major impact on infrastructure needs and reliability for gas supplies in the state. A facility that can provide 1 Bcfd of LNG supplies represents nearly 16 percent of the average daily need for natural gas in the state. This would significantly increase the needed *"slack capacity'* on interstate pipelines serving the state. LNG imports on the West Coast would enhance supply reliability. It is anticipated that this new supply would also temper the number and extent of price spikes experienced over the past three years. Competitive market forces will dictate the increase and timing for capacity from the above options.

# Chapter 5: Meeting Public Interest Objectives

This chapter first discusses how well we are meeting the goal of conserving resources and increasing the efficiency of the electricity system. Next, it assesses in more detail expectations for retail electricity and natural gas rates. Finally, it summarizes the environmental assessments that are the subject of the comprehensive ***2003 Environmental Performance Report***, a subsidiary report of this ***Electricity and Natural Gas Assessment Report*** and, ultimately, of the ***Integrated Energy Policy Report*.**

As required by SB 1389 (Section 25303 (b)), a full evaluation of public benefits would address economic benefits; competitive, low-cost reliable services; customer information and protection; and environmentally sensitive electricity and natural gas supplies. This first integrated planning report was not able to address the full range of the legislation in the time allowed. This report has not attempted to conduct a comprehensive assessment of either the economic benefits of electricity and natural gas markets, or customer information and protection *per se*. However, key pieces of such assessments can be found within this report and within the other subsidiary energy policy reports of the Energy Commission's ***Integrated Energy Policy Report*.** A more comprehensive discussion of public interest objectives and the progress of programs designed to achieve them is included in the ***Public Interest Energy Strategies Report***.

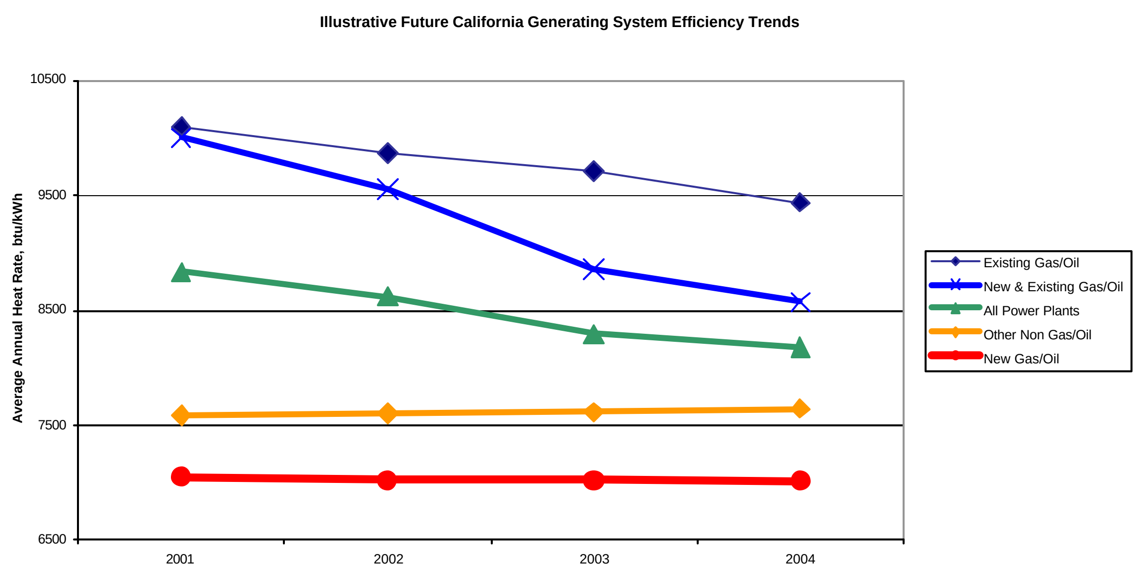
## Efficiency of Energy Consumption and Supply

We can minimize the resources needed to provide usable energy for consumers through three principal techniques: energy-efficient end uses and behaviors that reduce the need for power in the first place, using renewable resources instead of depletable resources, and making the remaining system more efficient. California already has an enviable track record compared to the rest of the U.S. on both how little power we use while supporting economic and population growth, and the lower environmental impacts of the built system. These trends can be extended through the policies supported in this report.

The future trend for per capita annual electric energy consumption and peak demand can be held flat with savings achieved from DSM programs, funded by the current level of the Public Goods Charge surcharge (**Chapter 2**, **Figures 2-8** and **2-9)**. An approximate doubling of DSM funding can cause a downward turn in the future trends for per capita electric energy and peak demand. By 2013 per capita demand would be 240 kWh per person, or 3 percent lower, than in the baseline trend. Natural gas DSM programs funded by the current level of the PGC surcharge are expected to steadily reduce per capita natural gas consumption over the next decade (**Figure 2-14**). Additional funding for natural gas DSM programs could reduce per capita natural gas consumption even more.

In addition to reducing the end use demand, fossil fuels can also be conserved by increasing the overall efficiency of the electricity system's use of fuel to provide power for end-users, and by increasing the proportion of power that comes from renewable non-fossil energy sources such as geothermal, wind, solar, biomass, and hydroelectric resources. Most new fossil-fired power plants are very efficient gas-fired combined cycle plants or even more efficient gas-fired cogeneration plants (**Figure 5-1**). Besides helping to meet load growth, they are displacing generation from old, less efficient power plants. Between 1990 and 2001, there was little change in the system's overall efficiency. But, with the addition of about 9,300 MW of efficient gas-fired generation, the average system efficiency has begun to drop from 8,800 Btu/kWh in 2001 towards a forecasted 8,200 Btu/kWh in 2004.[16]

**Figure 5-1**




The Renewable Portfolio Standard program is designed to increase the share that renewable power contributes to power sales. In addition to conserving fossil fuels, the increasing reliance on efficient gas-fired and renewable resources has attendant environmental benefits which are discussed in more detail at the end of this chapter.

# Electricity Retail Rates and Bills Outlook

This summary is supplemented by Attachment 6, *California Municipal Utilities Electricity Price Outlook*, (100-03-005) and Attachment 7, California *Investor-Owned Utilities Retail Electricity Price Outlook*, (100-03-003).

## Electricity Rates

Over the last two and a half years, IOUs have been collecting from customers more than enough revenues to cover their cost of electricity. This excess revenue will likely be used by the IOUs to cover the debt they incurred during the crisis of 2000/2001. Once this debt is recovered, rates will decrease; however, policy makers could allow utilities to use the funds for alternative purposes.

Under current Energy Commission staff projections, retail rates for all investor-owned utility (IOU) customers in California will most likely decrease in 2004, remain relatively constant for a couple of years, then will slightly increase through 2007 (**Table 5-1**).

**Table 5-1**
**IOU Retail Electricity Rates**
**Nominal ¢/kWh**

| Year | Residential | Commercial | Industrial |
|---|---|---|---|
| 2003 | 12.9 | 16.8 | 12.3 |
| 2004 | 11.7 | 12.8 | 8.4 |
| 2005 | 11.6 | 12.7 | 8.2 |
| 2006 | 11.7 | 12.7 | 8.2 |
| 2007 | 11.8 | 12.9 | 8.3 |

Source: CEC staff

If current trends in projected energy prices, utility plans and programs, regulatory decisions and assumptions prevail, retail electricity rates are likely to have the following attributes:

- A substantial rate decrease is likely in 2004 for Edison. For SDG&E customers, the rate decrease would likely be smaller. Rates for Edison and SDG&E after 2004 would slowly increase to capture the cost of energy and the effect of inflation. Rates for PG&E electricity customers depend on the bankruptcy settlement.

- Major IOU electricity rate component costs, except for the energy surcharges, have been established for the next four years. Therefore, major cost-based rate fluctuations are unlikely.

- Future retail electricity rates for the IOUs depend, to a certain extent, on the regulatory decisions of the Federal Energy Regulatory Commission, the California Public Utilities Commission, the State Legislature, and the Governor, rather than the spot market prices.

Rates for California's municipal utility customers are likely to decrease in 2004 due to the accumulation of excess net income funds, and the desire of municipal utilities to maintain competitive rates with investor-owned utilities. The municipal utilities in this assessment include Los Angeles Department of Water and Power, Sacramento Municipal Utility District, the City of Burbank Public Department, the City of Glendale, and Pasadena Water and

Power. The 2004 rates, and the rates thereafter, will most likely reflect the utilities' cost of generation. Cost of generation is projected to increase slightly every year through 2007 (**Table 5-2**). The rate analysis suggests:

- Rates could decline by as much as five percent in 2004 as a consequence of accumulation of excess funds for LADWP, Glendale, Burbank, and Pasadena; however, the rate decrease would be smaller once the estimated increase in energy costs and inflation are taken into account

- Future retail electricity rates for municipal utilities will depend on the price of natural gas and, to some extent, on the need to replenish their rate stabilization funds.

**Table 5-2**
**Municipal Utility Retail Electricity Rates**
**Nominal ¢/kWh**

| Year | Residential | Commercial | Industrial |
|---|---|---|---|
| 2003 | 10.5 | 10.4 | 7.5 |
| 2004 | 10.5 | 10.3 | 7.4 |
| 2005 | 10.8 | 10.6 | 7.4 |
| 2006 | 11.4 | 11.2 | 8.0 |
| 2007 | 11.9 | 11.7 | 8.5 |

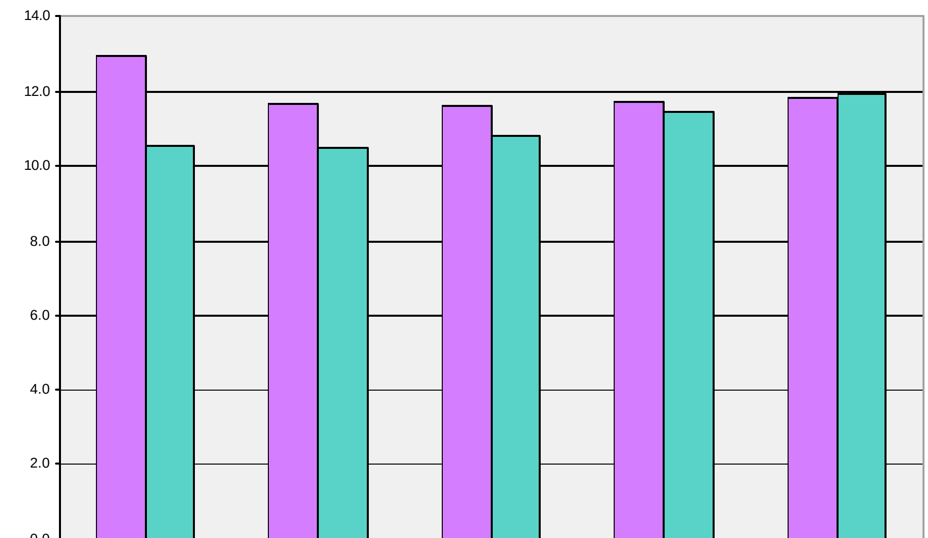
Source: CEC staff

## California IOU vs. Municipal Utility Electricity Rates

Current customers of IOUs face higher electricity rates than customers of municipal utilities. IOU residential customers pay up to 22 percent higher rates than their municipal counterparts. Rates for IOU residential customers are projected to decrease next year. Thereafter, they will slightly increase through 2007 (**Figure 5-2**).

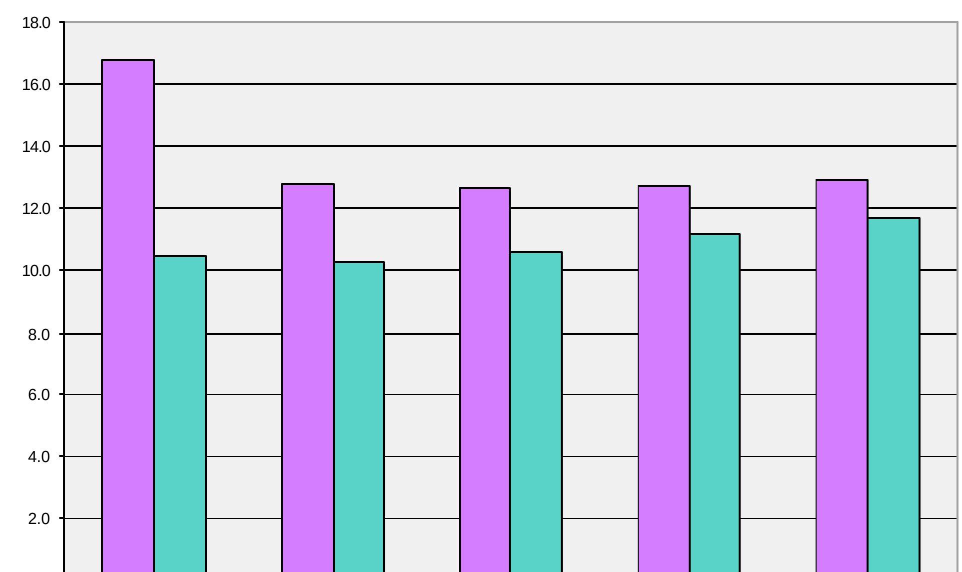
Electricity rates for commercial customers are currently 60 percent higher for IOUs than municipal customers. If the same rate structures persist for both IOU and municipal utilities, rates for IOU commercial customers could decline in 2004 and be level thereafter. The difference in rates between an IOU and a municipal commercial customer could be small by 2007 (**Figure 5-3**).

**Figure 5-2**
**Residential IOU/Municipal Electricity Rate Outlook**
**2003 – 2007**
**(Nominal ¢/kWh)**




| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| IOU | 12.9 | 11.7 | 11.6 | 11.7 | 11.8 |
| Muni | 10.5 | 10.5 | 10.8 | 11.4 | 11.9 |

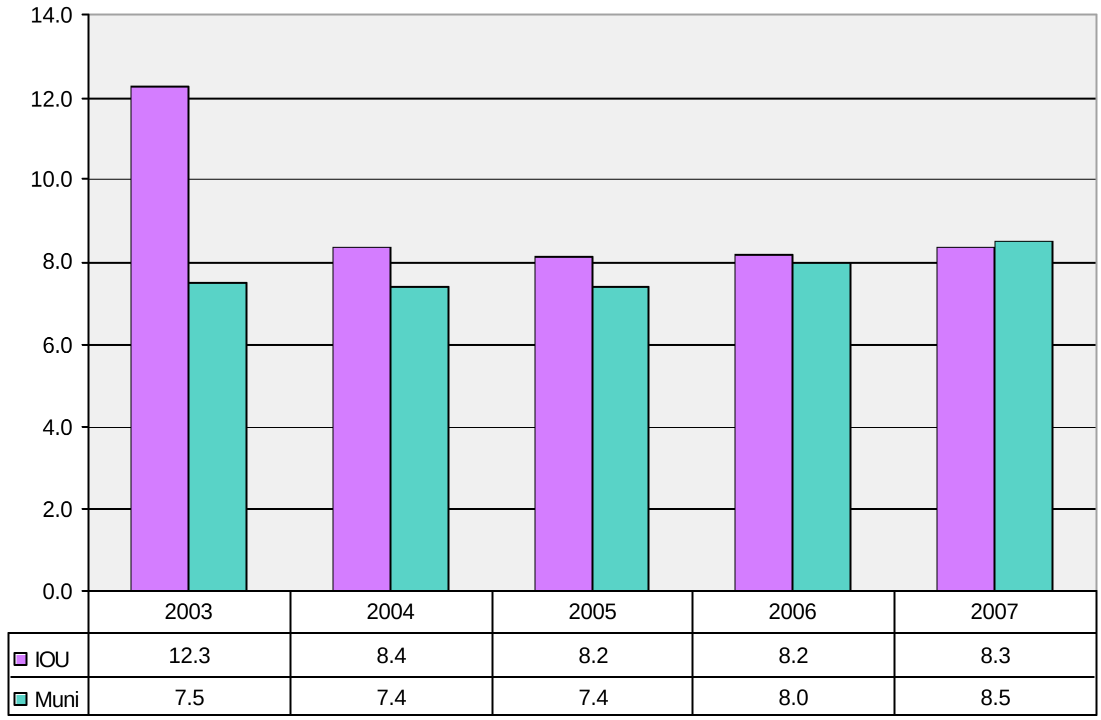
**Figure 5-3**
**Commercial IOU/Municipal Electricity Rate Outlook**
**2003 – 2007 (Nominal ¢/kWh)**




| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| IOU | 16.8 | 12.8 | 12.7 | 12.7 | 12.9 |
| Muni | 10.4 | 10.3 | 10.6 | 11.2 | 11.7 |

IOU industrial customers currently pay 63 percent more than municipal utilities industrial customers. Once energy surcharges decline, or disappear in 2004, the difference will be quite small. If current rate structures prevail, IOU industrial customers could be paying electricity rates similar to their municipal counterparts by 2006 (**Figure 5-4**).

**Figure 5-4**
**Industrial IOU/Municipal Electricity Rate Outlook**
**2003 – 2007**
**(Nominal ¢/kWh)**




The difference between IOU and municipal utility rates in California is significant; however, this difference will decline once the IOUs recover the cost of debt, which for some IOUs might happen in 2004.

Some large commercial and industrial firms are served through "direct access." These customers negotiate their own terms with suppliers, and the prices they pay are confidential.

## Electricity Bills - California vs. Western States

Although residential rates in California are much higher than those prevailing in other Western states, monthly residential bills are comparable to those facing customers in other states because average residential usage is lower in California. However, commercial and industrial customers are affected significantly by higher electricity rates in the state. Although commercial customers will most likely not leave the state, industrial customers may look for alternative places to locate their operations. This can reduce the job pool and affect the economic well being of the state.

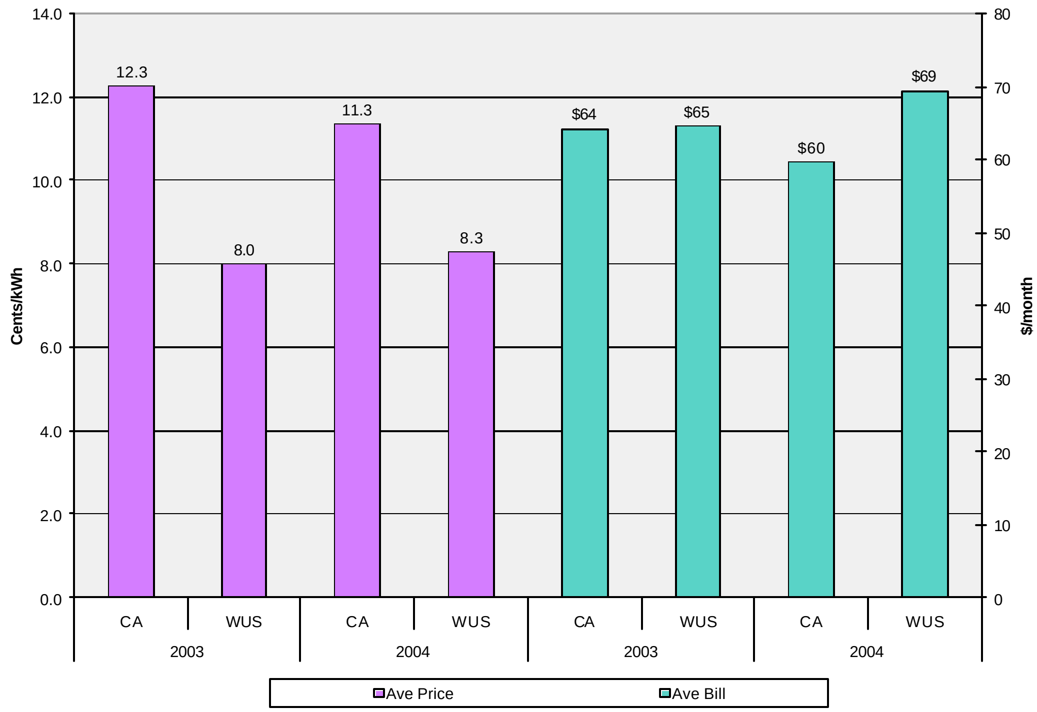
California's electricity consumers currently face considerably higher rates than consumers in other Western states. Residential, commercial, and industrial consumers currently pay as much as 53, 110 and 117 percent more in electricity rates in California, respectively, than similar consumers in other Western states. Although this trend will likely decline in 2004, rates could still be 37, 58 and 47 percent higher for California's residential, commercial, and industrial users, respectively (**Table 5-3 and Figures 5-5, 5-6, and 5-7**).

**Table 5-3**
**Comparison of Retail Electricity Rates in California and other Western States in Nominal ¢/kWh**

| Residential | | | |
|---|---|---|---|
| | **2002** | **2003** | **2004** |
| CA | 12.9 | 12.3 | 11.3 |
| Western US | 7.8 | 8.0 | 8.3 |
| % Difference | 67% | 53% | 37% |
| **Commercial** | | | |
| CA | 12.8 | 15.0 | 12.1 |
| Western US | 6.9 | 7.1 | 7.7 |
| % Difference | 85% | 110% | 58% |
| **Industrial** | | | |
| CA | 8.2 | 11.0 | 8.0 |
| Western US | 4.9 | 5.0 | 5.4 |
| % Difference | 68% | 117% | 47% |

Source: EIA and CEC staff. Western States include Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming, Oregon, and Washington

## Figure 5-5
## Residential Electricity Prices and Monthly Bills for California and Western State Consumers




## Figure 5-6
## Commercial Electricity Prices and Monthly Bills for California and Western State Consumers

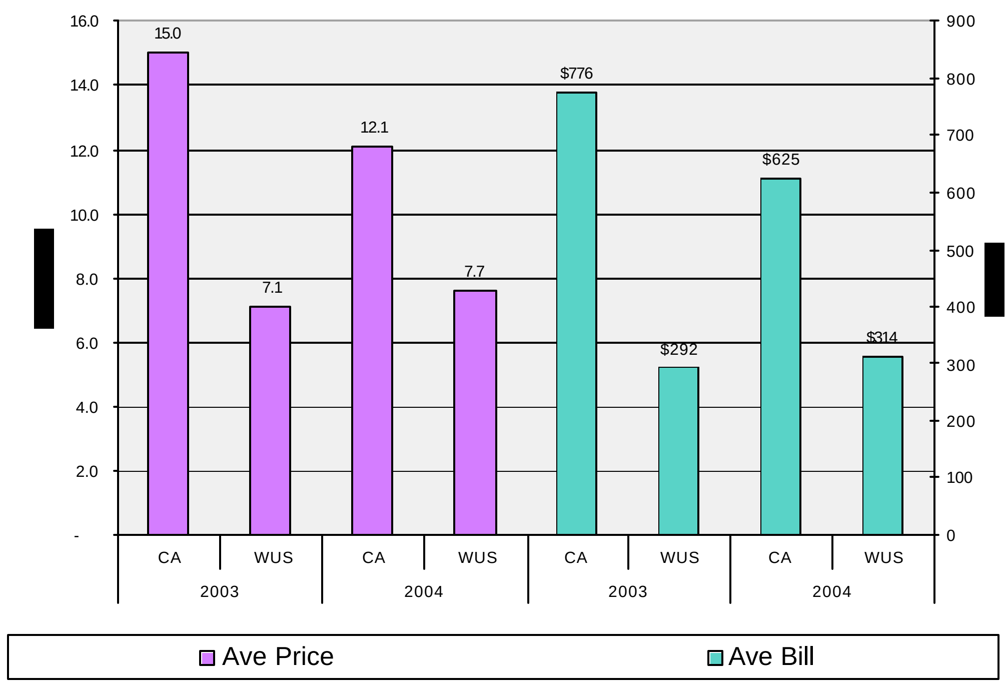
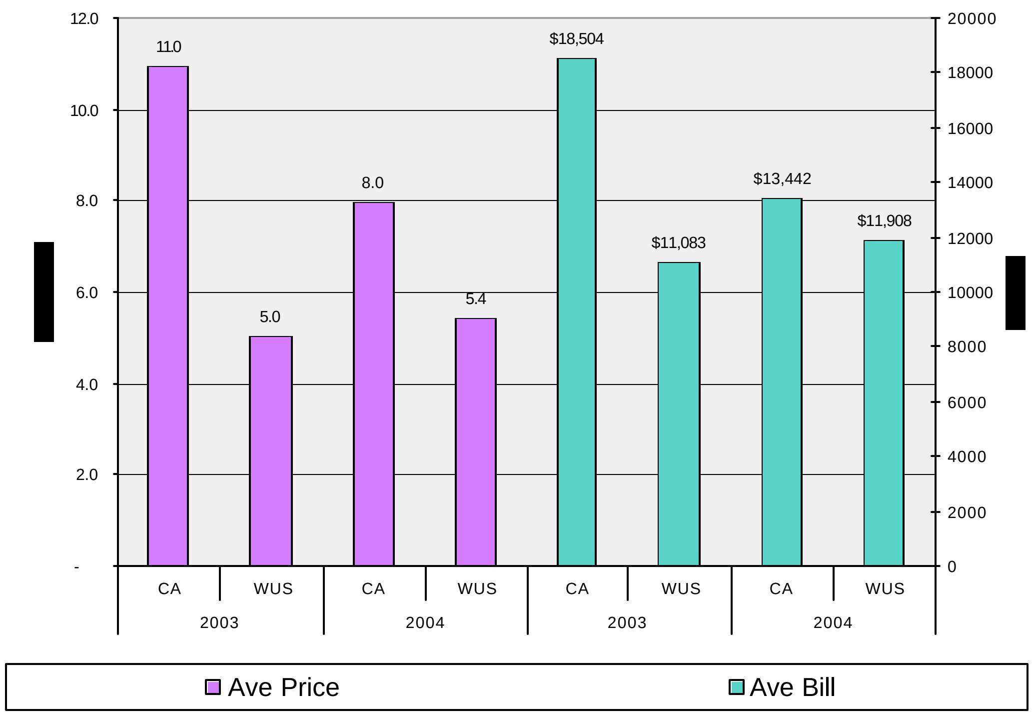


**Figure 5-7**
**Industrial Electricity Prices and Monthly Bills**
**for California and Western State Consumers**




Electricity bills for California's residential consumers are slightly lower than bills for similar consumers in other states. At the same time, residential consumers in California currently pay 53 percent higher rates. If a rate decrease projection for California's consumers materializes next year, a residential consumer in California would pay even lower electricity bills than residential consumers in other states (**Table 5-4 and Figure 5-5**).

California's commercial consumers, on the other hand, pay more than double in rates and bills than similar consumers in other states. Although the trend declines next year, the burden for commercial customers remains high. California industrial consumers fare relatively better than commercial customers. Current electricity bills for California's industrial customers are approximately 67 percent higher than for customers of other Western states. These bills could decline to be only 13 percent higher next year **(Tables 5-3 and 5-4 and Figures 5-6 and 5-7)**.

**Table 5-4**
**Comparison of Monthly Retail Electricity Bills in California and other Western States in Nominal $/kWh**

| Residential | | | |
|---|---|---|---|
| | **2002** | **2003** | **2004** |
| CA | $68 | $64 | $60 |
| Western US | $63 | $65 | $69 |
| % Difference | 8% | -1% | -14% |
| **Commercial** | | | |
| CA | $664 | $776 | $625 |
| Western US | $284 | $292 | $314 |
| % Difference | 134% | 166% | 99% |
| **Industrial** | | | |
| CA | $13,917 | $18,504 | $13,442 |
| Western US | $10,783 | $11,083 | $11,908 |
| % Difference | 29% | 67% | 13% |

Source: EIA and CEC staff. Western States include Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming, Oregon, and Washington

# Natural Gas Retail Price Outlook

Average annual natural gas costs are a smaller portion of energy bills than electricity. In 2002, the average California residence paid $356 for natural gas and $816 for electricity. The average annual commercial bill was $2,408 for natural gas and $ 7,968 for electricity. [17] Monthly residential natural gas bills are noticeable because they are bunched into the heating season instead of being spread evenly throughout the year. And, of course, these average annual and monthly bills mask wide variations among individual users. For some industrial customers, natural gas can be a significant cost, both as feedstock and as a power source.

High natural gas prices over the past few years have gained significant attention, impacting all market sectors. Natural gas bills have risen sharply, especially in the winter season when residential demand for natural gas is the greatest. Increasing costs to find and produce natural gas will cause natural gas prices to rise between 2003 and 2013.

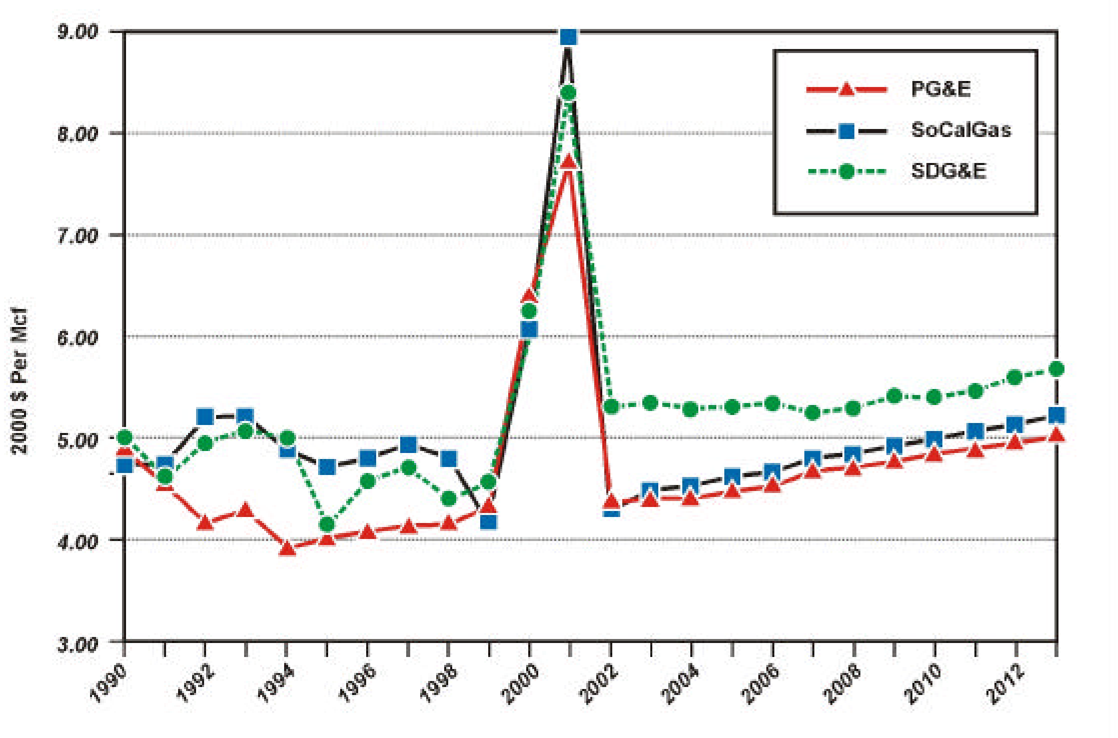
Natural gas prices for the end-user are made up of the wellhead prices, the cost of gathering and conditioning the natural gas, the price of interstate pipeline transportation, and utility costs of distribution. [18] The wellhead price comprises about 80 percent of the price for industrial and electricity-generation customers and about 50 percent for core customers.

**Figure 5-8** shows volume-weighted annual-average prices for all customers in the PG&E, SoCal Gas, and SDG&E service areas, expressed in year 2000 dollars per Mcf. These system-average prices are expected to settle between $4 and $6 per thousand cubic feet (Mcf).

During the next ten years, gas prices are likely to fluctuate above or below this basecase assessment due to short-term shifts in supply availability, seasonal and demand fluctuations, regulatory changes, and other factors affecting short-term market trends. **Figure 5-8** also shows the price spike of 2000-2001, when prices reached about $9 per Mcf, on an annual average basis, in some areas. The spike occurred because demand was strong, supply deliverability was tight, and price manipulation occurred.

In response to these price increases, producers increased drilling, and other market participants expanded pipeline capacity and storage facilities. At the same time, gas consumers conserved energy to decrease their demand, and lower utility bills. A slowdown of the national and California economies also contributed to lower demand. As a consequence, prices returned to the $4 to $6 per Mcf range after 2001. The long-term assessment calls for gas prices to remain between $4 and $6 per Mcf.

**Figure 5-8**
**Historical and Projected Utility End-Use Prices in California**
**Annual Averages**




Source: California Energy Commission

# Environmental Performance

The general environmental trends for the electricity generation sector are positive though significant impacts from fuel delivery and electricity generation and transmission remain on a regional basis, generation sector basis, and environmental media basis. Decreases in air emissions from the power plants are impressive and can be attributed to successful application of "Clean Air Act" regulations by State of California regulators (at the Air Resources Board) and local air quality management districts. Air quality levels continue to be poor throughout the state, and the relative contributions of power plant emissions to local air basin inventories and air quality varies regionally.

The tradeoffs between impacts to air, water and land are more complex. Impacts to aquatic ecosystems continue to be the most difficult to understand scientifically, and the most difficult to alleviate. For example, hydropower does not contribute to air quality impacts, but aquatic ecosystems at a watershed scale have been fundamentally changed by hydropower development and operation. Repowering a large natural gas-fired power plant at one of California's 21 coastal power plants means that new generation units with high thermal efficiency and very low emissions can be installed. Existing infrastructure can also be re-used, which minimizes new impacts to terrestrial habitats from new foundations, roads and transmission lines. But, the tradeoff can be continuing impacts to sensitive estuaries, bays and marine areas.

Electric transmission lines enable the effective transfer of electricity from areas of generation to areas of demand, which means that a wide array of energy resources can be brought to large urban areas from distant parts of the state, and western North America. But, the full environmental effect of transmission lines on birds, desert ecosystems, and forested regions has yet to be documented, and is an issue of concern.

Differences among regulatory systems contribute to these varying impacts to differing parts of the natural environment. Poor air quality impacts human health, so air emissions are closely monitored, well understood, and tightly regulated by an interlocking system of federal, state and local authorities. The impacts to water quality and aquatic ecology from power plants of all types do not typically tend to directly affect human health. This may be why impacts to river fisheries and coastal bays are more difficult to regulate and mitigate. The regulatory system for water quality and aquatic species is fragmented across multiple laws (i.e. Clean Water Act, Porter-Cologne, Federal Power Act, California Fish and Game Code, Warren Alquist and California Coastal Act) and multiple state and federal jurisdictions. Differing agencies have differing priorities and statutory mandates.

Energy imported from outside of California's borders means less impact to California's natural resources, and has positive effects for the economies of other states and countries. California utilities own more than 6,200 MW throughout the west, primarily coal-fired generation. Coal is a low cost and reliable energy resource, but emits higher levels of $NO_x$ and particulate matter, $CO_2$ and $SO_x$ than in-state natural gas-fired generation. Air quality in neighboring states tends to be better, so the net impact to air quality is less than if the plants were located in California. This scenario does not hold for Mexico. Poor air quality in the border region of Mexico raises issues of varying international regulatory standards, especially for power plants built to serve California energy markets.

Such examples of tradeoffs between regions - between impacts to air versus land versus water, or between impacts to a Southern California air basin compared to a Northern California watershed - are extremely difficult to assess given current structures of governance and regulation. The Energy Commission cannot yet report on cumulative energy effects, nor assess the relative contributions of electricity generation and transmission, to different air basins, watersheds and bioregions. Two root causes are a lack of systematic environmental monitoring data and compilation across all statutes related to the energy sector, and the lack of a scientific method to assess the variation in environmental effects across technology sectors and environmental media. As reported in the ***2003 Environmental Performance Report (100-03-010)***, lack of current, sufficient scientific environmental data hampers the Energy Commission's ability to fulfill its statutory responsibility to report to the Legislature, Governor and public on the environmental performance of all aspects of California's electricity generation and transmission system. Life cycle impact analytic methods may offer a promise to better understand the full systems-level effects of the state's energy generation and transmission system. Such methods require large amounts of environmental data however, and are complex when an energy system as vast as California's is analyzed.

Global climate change will create a series of effects on California's climate and hydrology that will in turn impact the state's wide array of bioregions and ecosystems. Many of the state's habitats and ecosystems are small and already stressed. The scale of climate change effects will be pervasive, and may alter ecological balances in specific ecosystems and bioregions. Specific electricity generation and transmission effects on local environmental systems may, in turn, become more acute. Electricity generation contributes to climate change, and will be affected by it as well. This may be the single greatest environmental issue before the state.

As summarized below for the various environmental media, the general environmental performance trend is positive. The environmental footprint of the energy system required to supply the state's people and economy is relatively small compared to that for other parts of the nation, and the world. Discrepancies in impacts to various parts of the natural environment, though remain large. The Energy Commission has direct jurisdiction over a relatively small portion of the state's electrical generation system. As cooperative relationships are formed with other state and federal agencies, and a more robust collective understanding of the state's energy system emerges, the Energy Commission will be able to more capably report on the complete extent of the environmental performance of California's electrical generation and transmission systems.

## Air Emissions

California's reliance on in-state generation from natural gas, the cleanest of the available fossil fuels, and the state's overall mix of energy resources - including hydropower and renewables - benefits the state's air quality. Statewide, combustion-fired electric generation comprises a relatively small portion of the state's average daily inventories of $NO_x$ (3 percent) and PM10 (0.47 percent), and a higher portion of the $CO_2$ (16 percent) inventory. California's electricity consumption, however, is responsible for much higher emissions, because the state imports a substantial amount of electricity from other states – some of which is generated by coal-burning power plants. Burning coal generates about twice the amount of $CO_2$ per unit of energy released during combustion than natural gas. Between 1996 and 2002, the generation emissions and emission percentages stayed relatively flat. The overall efficiency of California's electric generation system has continued to improve with the addition of new efficient combined-cycle power plants. Further additions of new efficient combined-cycle power plants, new renewable power plants, and energy efficiency and load management programs in the coming years will continue this trend. Some existing facilities have been displaced as a result of decisions to reduce the use of, retire, or replace with new natural gas combined-cycle units, driven in large part by the costs of upgrades that would be needed to comply with current air emission regulations.

Emissions control retrofit rules continue to be effective in reducing power plant $NO_X$ emissions. Implementation of the $NO_x$ emissions control retrofit rules for utility boilers over the last decade has resulted in 80 to 90 percent reductions in $NO_x$ emission rates per MWh from these facilities. Over 85 percent of California combustion-fired generation uses some form of $NO_x$ emission controls. Nearly 21,000 MW, or 60 percent, use selective catalytic reduction (SCR) for $NO_x$ emission control. Deployment of additional retrofit emission control equipment will continue based on consideration of ongoing cost for control equipment, dispatch of existing units, the attainment status and air quality management plan of the district, and possible regulatory changes.

California is making air quality progress in most regions, although in some regions progress has been slower than anticipated. For this reason new measures targeting existing generation, as well as other combustion sources, are being developed. Under existing rules, new generation will be more efficient and cleaner than the system averages, resulting in continued reduction in the emission factors. **Figure 5-9** shows how system averages are compared to potential new additions for $NO_x$ emission rates.

The recent merchant-owned capacity additions and former utility-owned fuel-fired boiler and combustion turbine facilities, with a capacity of about 23,100 MW, now operate as the swing or load-following units on a daily, seasonal, and emergency basis. These units tend to be dispatched to accommodate the swings in demand and availability of in-state hydro and imported sources. Generation from these facilities increased 145 percent between 1996 and 2001, with the main increases in 2000 and 2001 in response to limited hydro resources throughout the west (**Figure 5-10**).

Improvements in the $NO_x$ emission rate per MWh, resulting primarily from retrofit of the steam boiler facilities, limited the increase in $NO_x$ emissions that accompanied this spike in generation to 41 percent above 1996 levels. In 2002, when generation from these units dropped almost 40 percent compared to 2001, total $NO_x$ emissions from these units was 25 percent below 1996 levels, and the emission rate per MWh was 50 percent below that of 1996.[19]

**Figure 5-9**
**$NO_x$ Emission Rates:**
**System Averages and Potential Resource Additions**

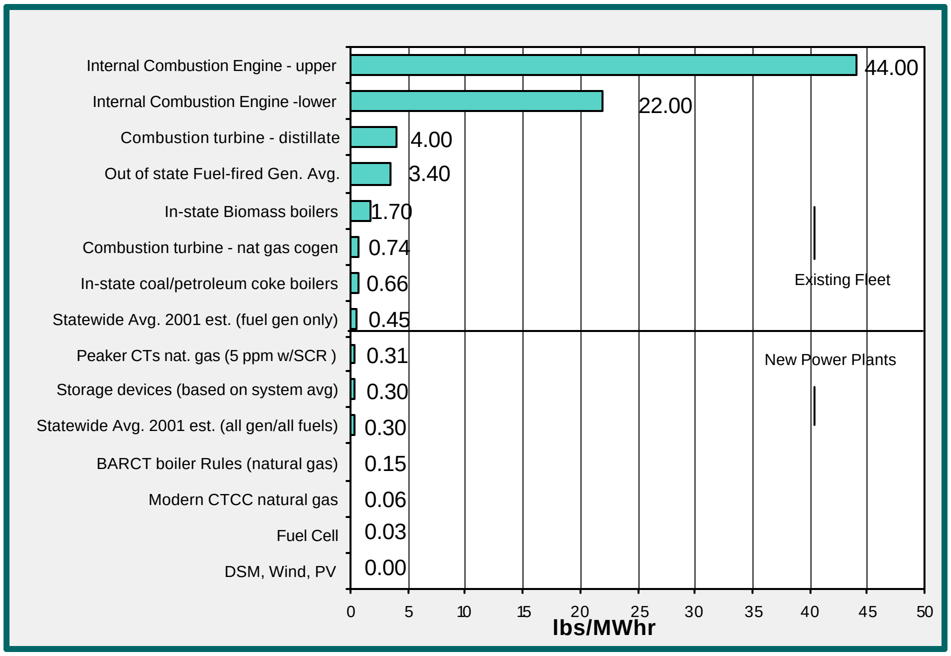
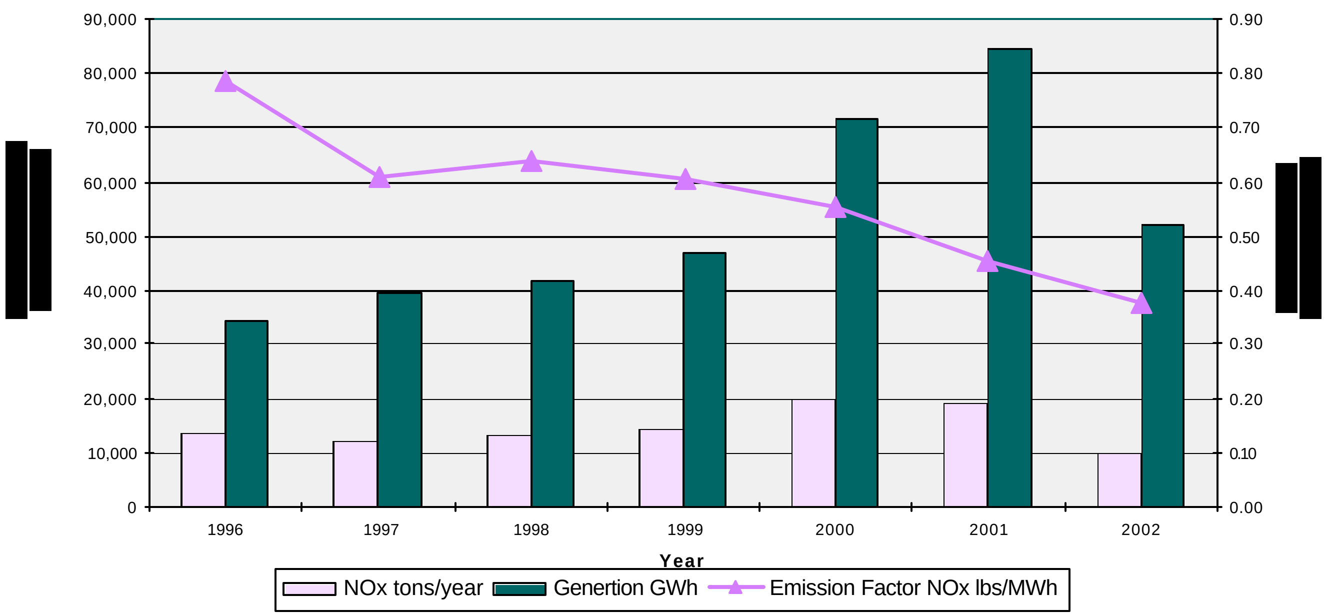
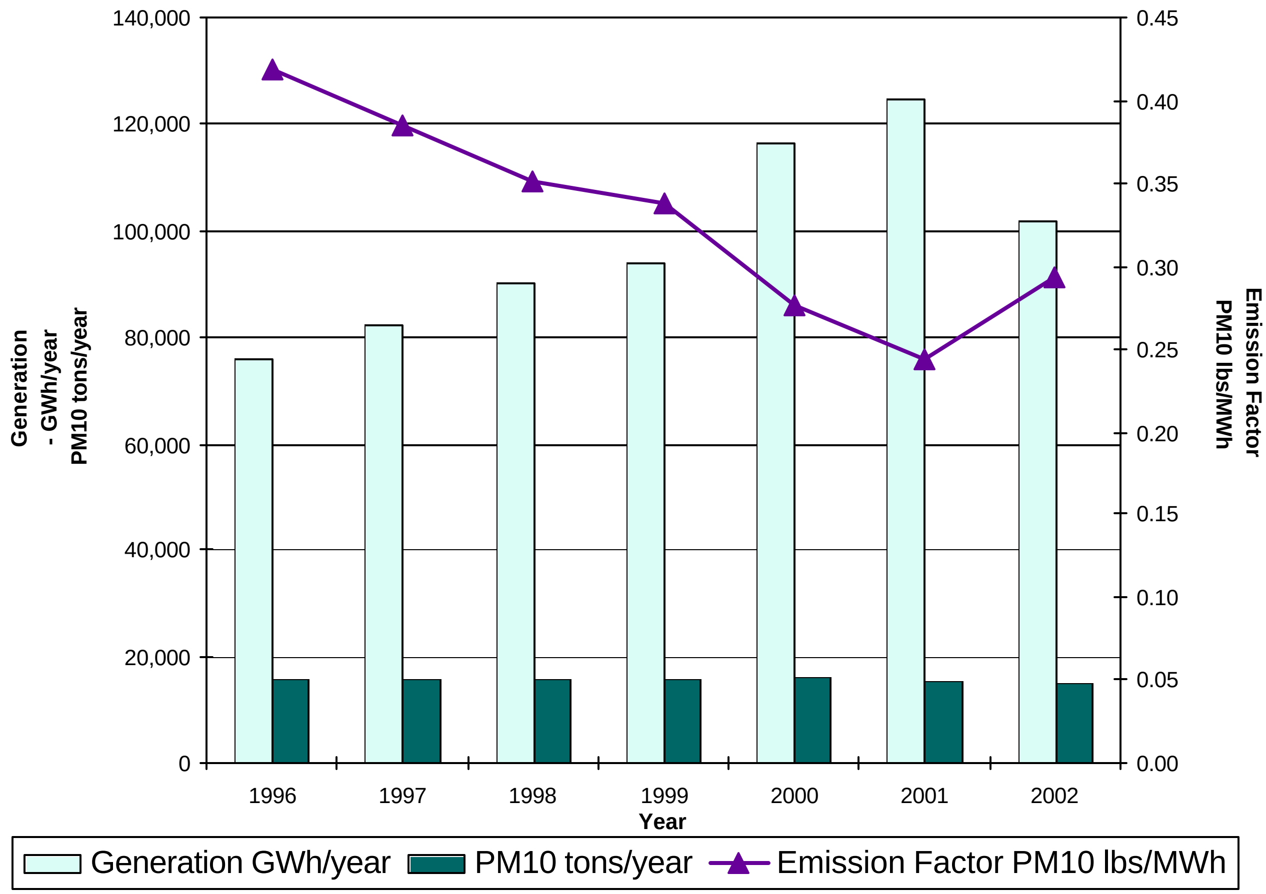



**Figure 5-10**
**Generation and $NO_x$ Emissions from In-state**
**Load Following Units**



Increases in gas-fired generation in 2001 and 2002 also resulted in increased emissions of particulate matter smaller than 10 microns (PM10). The level of PM10 emissions from fired electric generation in California depends almost entirely on the type of fuel combusted. Generation using natural gas results in very low PM10 emissions, while the use of coal and biomass can result in much higher emissions. **Figure 5-11** shows the trends in PM10 emissions and emission rates for the fired portion of the state fleet using data from the US EPA's E-GRID data base. While the data show a significant decrease from 1996 to 2001 in lbs/MWh emitted, this decrease is not representative of a change in emission rates of individual facilities. As is discussed above, this period saw a sharp increase in the natural gas portion of in-state generation, and the sharp dip in the PM10 emission rate is primarily a function of this resource mix change in 2000 and 2001.

**Figure 5-11**
**E-GRID PM 10 Emissions and Emission Factor**
**For Fired Generation**



Because emissions vary by region and season, further air emission reductions from the generation sector may be needed in California. The state's air quality regulators will likely continue to provide practical and innovative rules to address both existing and new generation sources, resulting in appropriate emission reduction contributions from the generation sector.

Significant emission gains have been achieved from retrofitting existing steam boiler power plants with emission controls, and permitting very clean new generation which can displace generation and emissions from older, less efficient plants. Further improvements in the air emissions performance of the generation sector will most likely come from technological advances in emissions control, efficiency improvements, or by decreasing reliance on combustion-fired generation through reduced demand or increased use of non-fired electricity sources. Agency coordination and research will be critical components to obtain timely and cost-effective advances.

As part of the evaluation of next steps in working to improve the state's air quality, the California Air Resources Board has initiated a proceeding to develop a guidance document for emissions reductions from existing combustion turbines. The development of the guidance concepts, and their potential adoption and implementation by local air pollution control districts, may affect the availability and cost effectiveness of existing combustion turbines, and would be an additional factor that could affect when some turbines are returned.

Out-of-state generation appears to exhibit an improving $NO_x$ emission factor, possibly due to the increased use of natural gas. Despite $NO_x$ emission rates being higher for out-of-state generation, significant differences in ambient air quality make it difficult to predict how $NO_x$ emissions from these plants might contribute to out-of-state air quality. It is encouraging that several new power plants close to the California-Mexico border are employing effective $NO_X$ control technologies.

# Global Climate Change Impacts

California has long recognized the potential dangers that climate change and variability can impose upon the state's populace, economy, and natural resources. The risks associated with increased climate change and variability represent a serious threat to the state's future, with possibly significant costs related to the state's water supply, agricultural productivity, forest health, energy production and demand, and coastal infrastructure. Projected impacts include hotter days, additional smog, sea level rise, and a 15 to 30 percent reduction in surface water supply to California's cities and farms over this century.

Taking appropriate measures to minimize current and future adverse impacts of global climate change is a priority for California, as highlighted by several recent legislative actions. On a national level California's total emissions are the second highest for any state, behind only Texas, due to the size of the state's economy and population. Greenhouse gas emissions, on a per person basis in California, are relatively low compared to the rest of the United States.

California's greenhouse emissions come from several sources with the primary cause being fossil fuel consumption in the transportation, industrial, and electricity sectors. The generation of electricity in California accounted for approximately 16 percent of all greenhouse gas emissions in 1999. This share is significantly lower than the national average, where closer to 33 percent of greenhouse gas emissions result from production of electricity. Because California imports a substantial amount of electricity from other states, including form coal-fired power plants, the state's electricity consumption is responsible for higher emissions of $CO_2$. **Figure 5-12** shows the trend in total annual carbon emissions from, and the carbon emission rate of, fossil-fired in-state generation. **Figure 5-13** allows comparison of California's in-state electricity generation mix with the average throughout the United States. Our in-state generation mix is significantly less carbon-intensive due to lack of in-state coal-fired generation, high production from hydro-electric facilities in the state, and the import of electricity from neighboring states.

One impact of climate change linked directly to electricity production is a shift toward warmer winters that are reducing the volume of the Sierra snowpack. This snowpack is the state's principal water storage and allows hydropower to serve as a dispatchable resource that can be used throughout the year. More than a century of river flow data show that warmer winters have lead to reduced snowpack, and earlier snow melt has reduced Sierra watershed late spring/early summer runoffs by as much as 10 percent. Earlier runoffs mean that less hydropower is available to help regulate the stability of the electricity system, or to serve summer peak demand, and less overall hydroelectric energy is available during the year.

While electricity production and industrial emissions are universally important sources, transportation is California's largest source of carbon dioxide from burning of fossil fuel. The ***Transportation Fuels, Technologies, and Infrastructure Assessment Report*** (100-03-0130) discusses strategies to reduce transportation greenhouse gas emission impacts.

**Figure 5-12**
**$CO_2$ E-GRID Emissions for the In-state Fired Capacity**

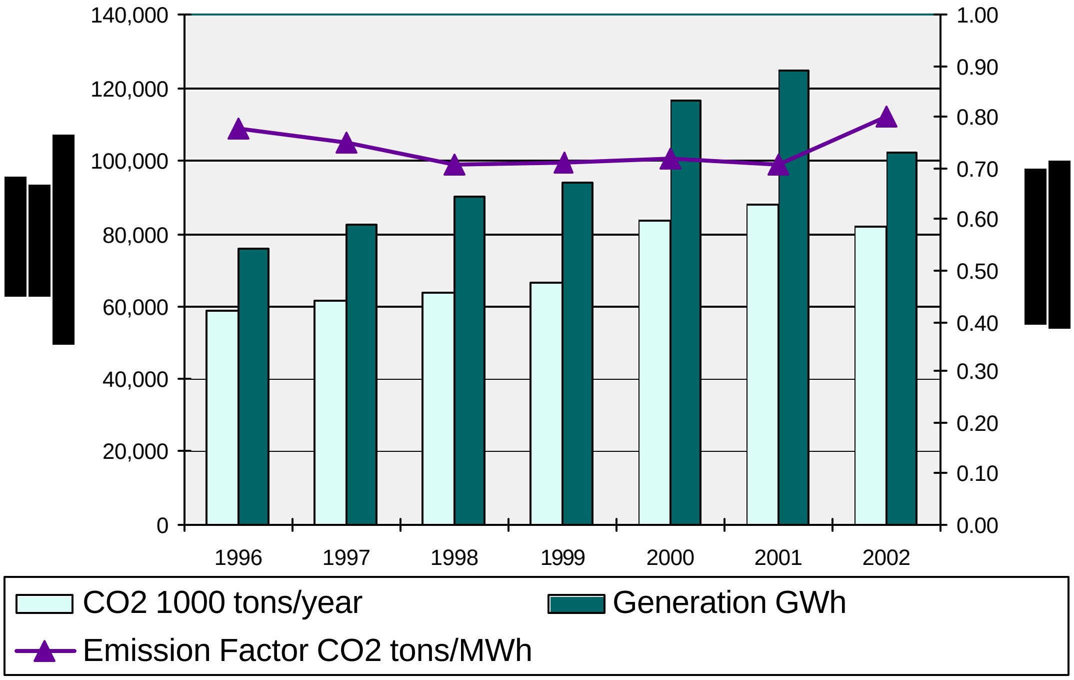
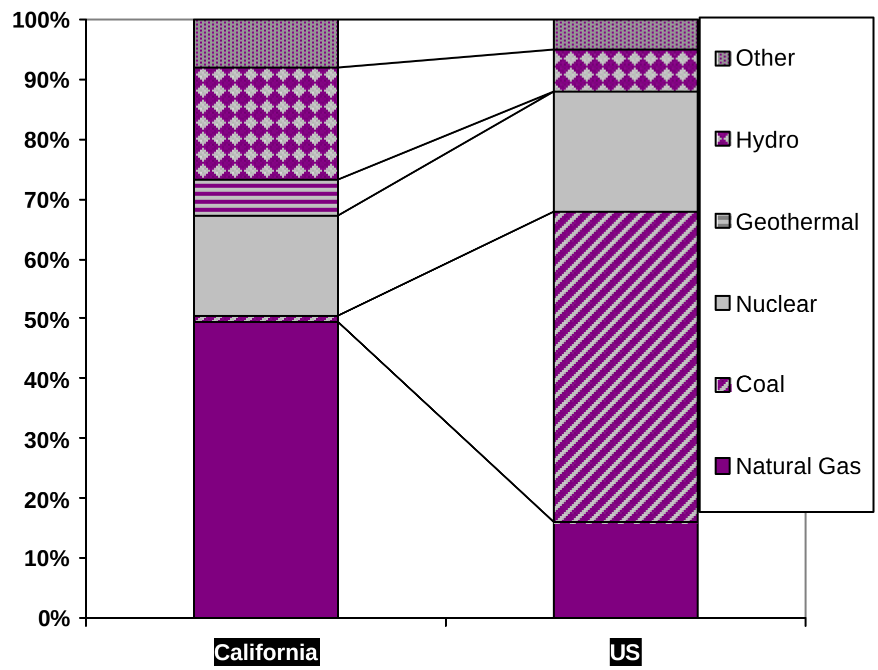



**Figure 5-13**
**Electricity generation mix in California and the United States**




**Source: eGrid2002pc, Version 2.01, U.S. EPA**

## Biological Resources

Habitat loss impacts to terrestrial biological resources have been mitigated for Energy Commission-reviewed projects. The eighteen operational natural gas-fired power plants licensed by the Energy Commission after 1996 caused minimal terrestrial biological resource impacts, and included the loss of only 225 acres of habitat. Power generation development from 1996 through 2002 used approximately 3,900 total acres of land, but the footprint of fuel development is still being researched. Because California's most sensitive species tend to occupy small habitat ranges, energy development projects have the potential to cause impacts when built nearby. Use of previously disturbed lands for energy projects can minimize such effects.

California's 31,720 miles of electric transmission lines and 11,600 miles of natural gas pipeline rights-of-way can contribute to habitat loss, fragmentation and degradation. Electric transmission and distribution lines can cause bird mortality from bird strikes and electrocution. Electric transmission lines can cause wildfires; but between 1996 and 2002, the number of wildfires caused by power lines decreased from 284 to 181, annually. New transmission lines to improve system reliability and link new renewable generation resources to the grid may need to be mitigated to reduce the risks of increasing impacts to wildlife and habitats.

Mitigation of aquatic impacts from hydro operations and once-through cooling continues to be a controversial environmental issue. Twenty-one natural gas and nuclear power plants, totaling 23,883 MW, are located on the coast or on estuaries and use hundreds of millions of gallons of water per day for once-through cooling. Impacts to marine and estuarine ecosystems from the destruction of aquatic organisms can be adverse and an issue of concern. Case-specific information is needed to evaluate impacts and to determine appropriate mitigation. Recent proposals for repowering at five coastal power plants did not include changes to once-through cooling water systems that would substantially reduce impacts to aquatic organisms, though mitigation has been required or proposed as part of the projects. Recent and anticipated change in US EPA rules may require these systems to be substantially modified or replaced to reduce their effects on marine organisms.

Salmon or steelhead habitat is found at hydropower facilities in the Sacramento River basin, the San Joaquin River basin and on the North Coast. Very few California hydropower projects have adequate (as currently defined), fish passage structures for migrating salmon and steelhead. Hydropower impacts to salmon, steelhead, native trout and other species continue to be significant. Thirty seven percent (5,000 MW) of California's hydropower system will be relicensed by the Federal Energy Regulatory Commission between 2000 and 2015, presenting opportunities to address and mitigate impacts to salmon, trout and other aquatic species. The Energy Commission will continue to provide support to other agencies seeking to restore salmon fisheries, and other river species and habitats, during relicensing of hydropower projects.

Nitrogen deposition from new power plants and repower projects has potential cumulative impacts if the power plant is within the vicinity of nitrogen sensitive habitats, such as serpentine soil and desert communities. Potential nitrogen deposition impacts from new power plant proposals is emerging as an issue of concern. Case-specific information is needed to evaluate nitrogen deposition impacts to determine appropriate mitigation.

About 35 renewable energy facilities representing about 400 MW of capacity have been built since 1996, but a substantial increase in renewable generation will result from California's new Renewable Portfolio Standard. Wind energy will play a large role in meeting the Renewable Portfolio Standard. Bird mortality from strikes with turbine blades continues to be the primary biological resources issue concerning wind energy. Building integrated solar photovoltaic and biogas-fired electric generators at landfills and sewage-treatment plants have the least risk of impacting biological resources. Other renewable energy types, such as biomass using in-forest fuels, could have wildlife-friendly benefits if biological resource protections were integrated into the planning.

# Water Resources

## Water Supply

Competition for the state's limited fresh water supply is increasing and in some years contractual obligations to supply water cannot be met. Water use for power plant cooling can cause significant impacts to local water supplies, but tends to be a relatively small use at the aggregate state level.

Since 1996, an increasing number of new power plants have been sited in areas with limited fresh water supplies. More than 5,700 MW of new power has been constructed or is being considered within Southern California. As a result, use of fresh water for power plant cooling is increasing.

Fresh water use can be reduced or eliminated by use of recycled water or degraded groundwater, alternative cooling technologies, and zero liquid discharge (ZLD) systems. These alternatives to fresh, high quality water are technically feasible and practicable.[20] Of the 4,516 MW of new generation capacity brought on-line in California between 1996 and the end of 2002 for which Energy Commission staff has detailed water use information, more than 1,400 MW (31 percent) is cooled using recycled water.

Alternative cooling options, such as dry cooling, are available, commercially viable, and can reduce or eliminate the need for fresh water. Two projects using dry or air cooling became operational in 1996 and 2001. A third project using dry cooling in San Diego County is currently under construction.

## Water Quality

Water quality impacts to surface water bodies, groundwater and land from waste water discharge are being increasingly controlled through use of technologies such as zero liquid discharge systems. ZLD systems eliminate wastewater discharges to land or water and produce purified water streams for re-use in plant processes. Of the 4,516 MW of new capacity brought online between 1996 and the end of 2002 for which Energy Commission staff has detailed water use information, 12 percent use zero liquid discharge. More than 35 percent of the projects under licensing review or under construction will use this technology.

Continued use of once-through cooling at existing and repowered power plants perpetuates impacts to aquatic resources in the coastal zone, bays and estuaries. No power plants using once-through cooling have been proposed for new California coastal sites in the last two decades. Proposals to repower existing generation units at these sites have included proposals to continue the use of the once-through cooling system infrastructure.

Hydroelectric facilities can cause permanent alterations to stream flows, raise water temperatures, alter dissolved oxygen and nitrogen levels, and cause changes to the aquatic environment. These facilities can also provide benefits including water storage, flood control, and recreation. As of 2003, only a small portion of California's hydropower system meets current state water quality standards**.** Only six of 119 projects licensed by the Federal Energy Regulatory Commission have Section 401 Clean Water Act certification from the State Water Resources Control Board, and three more are nearly complete. These nine projects total 275 MW, which is about two percent of California's hydroelectric generating capacity.

Two potential policies relating to water supply and water quality should be considered for adoption by the Energy Commission:

- Any power plant applicant should be required to use water conservation cooling alternatives or reclaimed water, or prove these are not practicable. Such a policy could increase the influence of recycled water availability as a site selection factor for new power plants and reduce impacts on local water supplies.

- The discharge of liquid wastewater to land, groundwater or surface water bodies by power plants should be prohibited, and zero liquid discharge technology should be required unless proven not practicable. Such a policy could reduce water quality related impacts from power plant wastewater and increase the efficiency of water use in these facilities.

## Hydroelectric Plants Combine Environmental and Societal Effects

Hydro facilities provide a variety of social benefits (e.g., water supply, electricity, flood control, recreation), but also can create significant impacts to aquatic ecosystems in rivers and streams.  Important environmental restoration benefits can be achieved through hydropower relicensing before the Federal Energy Regulatory Commission, and through selective, targeted decommissioning projects.

The Energy Commission has been working with the Secretaries for Resources and Environmental Protection to determine whether greater environmental protection is needed for California rivers and streams affected by hydropower development and operation. Energy Commission staff have evaluated changes in energy production from hydro decommissioning projects to restore salmon and steelhead habitat. Staff determined that the projects should have little appreciable aggregate effect on electricity supply or cost for California. The Commission will continue working with sister state agencies in assessing the environmental and energy effects of specific proposals to modify or decommission hydroelectric projects in California, subject to staff availability.

# Societal Effects

The societal effects of power plants assessed in the ***2003 Environmental Performance Report*** include land use compatibility, socioeconomic resources, environmental justice, and cultural resources. The key findings and conclusions from this report are summarized below.

## Land Use Compatibility

Local and regional land use and development planning efforts seldom designate sites or corridors for energy facilities such as electric power plants and transmission lines, and energy facility proponents are seldom involved in these long range efforts. 40 percent of Energy Commission siting cases from 1996 through 2002 required a general plan amendment or zoning change, or other local actions like parcel map changes or Williamson Act cancellations, although it is unclear if this is typical of other major industrial development.

In rapidly growing urban areas, energy infrastructure development and repowering often occur very close to sensitive community resources such as new residential areas, schools, and recreation areas, which can lead to intense controversy and delay the facility siting process. Existing coastal power plants are generally located in areas that have experienced significant development and residential growth, and the repowering of those projects has caused, and is likely to continue to cause, local debate and controversy.

## Socioeconomic Resources

The 17 power plants permitted by the Energy Commission since 1996 that were on-line by December 31, 2002, added 4,418 MW in generation capacity, and have resulted in approximately 3,900 peak construction jobs, 125 operations jobs, capital costs of approximately $1.5 billion, and, for fiscal year 2002-2003, approximately $23 million in property taxes.

The ***2001 Environmental Performance Report*** estimated a 10-to-1 ratio of direct peak employment construction jobs to direct operation jobs for power plants. Data from the permitting of the non-emergency power plants approved by the Energy Commission since 1996 that were online by December 31, 2002, show this ratio was 25-to-1. This increase may be in part a result of faster construction cycles to meet the demands of the California energy crisis. Existing large steam boiler plants typically have 40 to 50 maintenance and operation employees. The gas-fired simple-cycle and combined-cycle power plants that are now being built have a range from only 2 to 24 maintenance and operational workers.

State law prevents public agencies such as the Energy Commission from imposing fees or other financial mitigation for impacts on school facilities. The school impact fee that can be levied by a school district usually ranges from $2,000 to $6,000 per power plant project. Municipal utility districts are exempt from these fees.

Starting in January 2003, the State Board of Equalization (BOE) assesses all privately owned electric generation facilities over 50 MW, including facilities divested by the public utilities that had been assessed by counties after deregulation. Some cogeneration and renewable facilities will continue to be assessed by counties. The BOE will assess at fair market value and revenues will be distributed to those jurisdictions located in the tax rate area where the power plant is located.

## Environmental Justice

The Energy Commission and the California Department of Transportation were the first state agencies to include environmental justice concerns and demographic information in their environmental impact analyses. The Energy Commission's approach to environmental justice emphasizes local mitigation and seeks to reduce environmental impacts that could affect local populations to less than significant levels. Of the projects identified as having greater than fifty-percent minority populations within a six-mile radius, appropriate mitigation has been identified to reduce significant impacts to less than significant levels, thereby removing any potential for an environmental justice issue (high and adverse disproportionate impact associated with a proposed project).

Power plants proposed in densely populated urban areas are often sited where residential land uses encroach on older industrial areas. Community involvement related to environmental justice during siting cases has primarily occurred in proposed power plant cases in the large urban areas of Los Angeles and San Francisco.

## Cultural Resources

Most facilities approved for construction and operation by the Energy Commission have involved archeological, historical or ethnographic cultural resource issues. Native American sacred sites and areas of traditional concern are particularly sensitive aspects of ethnographic concerns. One of the most significant cultural resource finds is the discovery of previously unknown Native American burials during construction.

# Chapter 6: Problems and Risks

## Electricity Infrastructure and Markets

### Introduction

The capacity surplus from 2004 through 2006 makes the reliable delivery of electricity at stable prices likely during this period. This outcome also minimizes the risks associated with uncertain amounts of capacity additions and retirements through 2006. This surplus will shrink as demand increases, however, leaving ratepayers exposed to potentially higher prices and an increased risk of delivery interruptions. In the absence of an energy policy which guarantees resource adequacy, ratepayers face the renewed risk of high prices and outages by 2007. Given this risk, policy makers must put an effective resource adequacy and long-term procurement framework in operation during 2004.

California's fundamental energy problem stems from the inflexibility of both energy supplies and demand that constrains the energy market's ability to respond quickly to recurring adverse shocks to the system. Adverse shocks occur as a result of some combination of extreme temperature, extreme drought, unplanned facility outages, and forecast error which periodically create recurring supply and demand imbalance episodes. Because of their underlying sources, these shocks are not precisely knowable. They can only be forecasted in a probabilistic sense. These extreme adverse shock episodes make California vulnerable, as we witnessed in the crisis of 2000-2001, to high costs, emergency outages, and a reduction in normal environmental safeguards.

Inflexible, unresponsive supply and demand are an important threat to realization of SB1389's public interest objectives. The need for public interest strategies arises because meeting public interest objectives is one area where we cannot depend on the private market to address the situation adequately. Partly, this is because many of the decisions necessary to increase supply and demand responsiveness entail regulatory oversight and approval. Such actions include slack pipeline capacity, additional storage, and dynamic demand responsive pricing. As a consequence of their ability to profit from inflexibility, market participants have inadequate incentive to invest in increasing flexibility. Well thought out public interest energy strategies can help alleviate this problem by expanding the menu of options available to increase the flexibility of energy supply, demand and transmission.

## Ensuring Reliability: The Market Challenge

Under the current hybrid structure, capacity is provided by both load-serving entities (owned generators and contract resources) and merchant generators. As the latter make additions, retirements and performance decisions based solely in response to market assessments, it is much more difficult than under traditional regulation for the state to ensure that:

- In-state capacity participates in California's energy markets and offers energy into these markets at reasonable prices,
- Capacity will be built before it is needed to ensure resource adequacy,
- The retirement of capacity does not threaten reliability or lead to excessive price spikes that deviate from a cost-based standard, and
- Capacity is added in areas where it is needed for local reliability, and can provide maximum economic benefits given the existing transmission grid.

Even if there is enough "steel in the ground" to meet demand, it may not be certain from hour to hour that enough of it will actually be generating electricity. Under the traditional vertically-integrated structure this was not a concern, as real-time grid operation was performed by an entity which had generation capacity under its direct control. The creation of an independent system operator, separates operation of many resources from ownership and control. Much more coordination among niche players in the industry is now required. This decentralization of the formerly integrated utility creates the possibility that load serving entities (LSEs) will rely on capacity that has failed to offer itself into the spot market to meet a share of load. Under these circumstances the CA ISO must somehow "encourage" generators that have not offered themselves into the market to provide energy. Market design proposals being considered by the CA ISO are attempting to resolve this problem.

## Efforts to Achieve Resource Adequacy Requirements

The CPUC is developing resource adequacy requirements for IOUs as part of its long-term procurement proceeding and is examining its authority to either impose similar requirements on ESPs or to assign this responsibility to IOUs. In this proceeding, the Energy Commission has fostered a review of municipal resource adequacy issues. In principal, these two parallel efforts should result in a common or complementary set of resource adequacy requirements being established that covers all LSEs.

All stakeholders have realized the importance of ensuring resource adequacy, and many proposals for stabilizing this market design element have been offered over the last few years. There is widespread agreement on the need for load-serving entities to take responsibility for ensuring resource adequacy. Under the current industry structure, the nature of the "obligation to serve" varies across classes of LSEs. For utilities, the obligation is absolute. The CA ISO and other control area operators already enforce standards for guaranteeing operating reserves in the near-term market. Municipal utilities have partnered with the Energy Commission to demonstrate their willingness to guarantee resource adequacy for their customers.

In the initial market design, direct access providers could "return" their customers to utility service. This shifts risk from the latter to the former. If direct access providers (or their customers) can respond to adverse conditions by shifting the obligation to serve back to a utility without cost, they face less risk associated with high wholesale prices and thus have less of an incentive to facilitate the addition of new capacity when it is needed. The utility faces additional risk: that it must suddenly serve additional load, an event most likely to occur when spot market prices are high. The suspension of direct access pursuant to AB1x-1 makes such ESP behavior less likely, because once returned a direct access customer cannot easily escape from bundled service again. The California Public Utilities Commission, in R. 01-10-024, is developing resource adequacy requirements for investor-owned utilities and investigating how to address this issue for direct access and community aggregator providers.

Although it appears that there is widespread agreement that resource adequacy requirements are needed, there is little agreement about the nature of the specific requirements. A useful starting point for principles to guide development of these requirements was included in the Energy Commission Staff/California Municipal Utilities Association working paper.[21] They are:

1. A public demonstration by LSEs of a performance-based resource adequacy plan, approved by the LSE's applicable regulatory authority;

2. Appropriate application of a resource adequacy program by each LSE so that free riding on the resource adequacy provided by others is minimized;

3. Periodic reporting by LSEs to their control area operator or RTO (if established) to demonstrate that planned resource commitments are matched to load forecasts. Periodic reporting by generators of commitments to LSEs and remaining available capacity, reported by generators to their control area operator or other RTO;

4. A demonstration that each LSE has the necessary authority to implement its resource adequacy obligations;

5. LSE discretion within the framework of its regulatory authority in planning, procurement, and operation of its power portfolio is maintained;

6. Arrangements, perhaps formalized, through tariff provisions or protocols that describe the actions the LSE and its control area operator will take when LSE resources do not fully cover its loads and appropriate reserves.

Pursuing resource adequacy throughout the Western Interconnection is also important to ensuring that the electricity system is reliable. California is not an island, independent from the rest of the Western Interconnection. The high prices that the spot market suffered in 2000 and 2001 were common across the West, although California's consumers and institutions received more harm than others, because we had a greater exposure to spot markets than most of the rest of the West. Existing institutions like Western Electricity Coordinating Council (WECC) and new ones like Seams Steering Group – Western Interconnection (SSG-WI) are attempting to bring improved focus on the assessment portions of resource adequacy. While these efforts are important, ultimately achieving resource adequacy will require the regulatory agencies in the Western states to embrace the need for explicit resource adequacy requirements, and then to design and implement them.

Forums in which resource adequacy requirements are being formulated include: the CPUC long-term procurement rulemaking putting forward a variety of ideas for IOU and ESP requirements; the Integrated Energy Policy Report proceeding in which municipal utility issues have been examined and moved forward at least one step; and the Committee on Regional Electric Power Cooperation (CREPC) efforts, supported by staff, which are contributing to improving assessment efforts and raising resource adequacy issues to the attention of other western regulators. At this point, it appears that California is out front in its efforts to develop specific requirements.

## Reducing Dependence on Natural Gas

Chapter 4 presented methods for mitigating the risk of high natural gas prices in the near-term. Short-term contracts, financial hedges, and storage can reduce exposure to the spot market and the likelihood of price spikes. These do not address the additional risk that dwindling North American gas supplies can only meet increasing demand at higher prices than have historically prevailed. This risk will grow during the coming decade if only because the state will become increasingly reliant on natural gas as a generation fuel. These risks associated with longer-run changes in the price of natural gas can only be mitigated by either developing new sources of natural gas, *e.g.*, LNG imports, or reducing the demand for natural gas as a generation fuel. The potential development of new sources of natural gas and its possible impacts are discussed elsewhere in this report.

Reducing the use of natural gas in electricity generation can be accomplished by the following:

- Replacing older, inefficient gas-fired power plants with newer plants that require less fuel,
- Reducing the demand for electricity in California, and
- Replacing gas-fired generation with generation from other fuel sources.

Natural gas is conserved by relying more on efficient new gas-fired generation than on the existing, older and less efficient power plants. The replacement of older gas-fired plants with newer ones has been taking place since 2001 and will continue through the remainder of the decade as new projects come on-line. Growth in the state's demand for electricity will still cause an increased reliance on natural gas as a generation fuel. Even with continued funding of energy efficiency and DSM programs at present levels, and even if the conditional mandates of the Renewable Portfolio Standard are met, natural gas-fired generation in California as a share of the state's electricity needs is still forecast to increase from 34 percent in 2004 percent to about 40 percent in 2013. In low-water years, reductions in available hydroelectricity will push this percentage even higher.

Dependence on natural gas can be lessened by reducing the demand for electricity. Programs which reduce the consumption of electricity have the greatest impact on natural gas demand if they are targeted at hours of peak electricity use, when the most inefficient power plants are called on to generate. During peak hours in the summer, the system's incremental heat rate is 12,000 Btu per kWh or greater. Reductions in demand during early morning hours or in the spring runoff season will have as much as 40 – 50 percent less impact. Reductions during peak summer hours also have the greatest impact on ratepayer cost and its volatility, as it is during these hours that the largest share of electricity is traded at both the spot market price and at other prices determined by the underlying gas price. How much the DSM programs cost and how the actual demand reductions they induce affect the generation system will determine how cost-effective these programs are at reducing dependence on natural gas.

Increased generation using other fuel sources will also reduce the demand for natural gas. Legal, political, environmental and cost issues make nuclear, large hydroelectric and coal generation unlikely candidates for offsetting natural gas generation. Energy Commission studies have indicated that the development potential of wind, geothermal, and biofuel generation is substantial and that the costs of these technologies are decreasing. The new Renewable Portfolio Standard Program should increase both the total amount and the percent share of electricity generated from renewable energy sources, offsetting generation that would otherwise have been gas-fired. This result depends on the renewable power having a market value that, together with a supplemental energy payment from funds provided through the Public Goods Charge, will result in a total payment to the plant developer that is sufficient to spur the plant's construction. It is too early to tell how much this program will cost, as the first RPS auctions will not be held until 2004.

As is the case for programs that reduce electricity consumption, renewable generation will displace the most natural gas if it is available during hours of peak electricity use. The extent to which increased generation from renewable sources can reduce and stabilize wholesale energy costs will depend on a number of factors. For example, renewable energy bought at fixed prices can have a stabilizing economic effect.

## The Need for Adequate Information for System Monitoring

Policymakers and regulators will require accurate information regarding market conditions and supply adequacy. This means that regulators and agencies responsible for assessing market conditions and capacity needs will require the following information:

- Details regarding contractual obligations which encumber in-state capacity. This includes the nature of commitments to load-serving entities, marketers and large-end users both in- and out-of-state. These should be provided by generators as a condition of accessing the bulk transmission grid.

- Short- and long- run resource plans of all load-serving entities in California, including specific terms that may prescribe the physical source of energy purchased under contract, and the firmness of delivery.

- The amount of spot energy or capacity bid into CA ISO markets by out-of-state generators.

In the absence of the above, it is not possible to assess the amount of unencumbered capacity that is or will be available to meet residual demand (load for which LSEs have yet to secure a supply of energy). If this assessment cannot be made, it is not possible for the state to accurately evaluate the need for new capacity or the risks associated with the retirement of large plants.

The types of information described above are market-sensitive. Accordingly, data that is not necessary to evaluate resource adequacy (e.g., pricing terms) would not be reported. In addition, proprietary information that is submitted would be considered confidential.

# Natural Gas Infrastructure and Markets

One of the six action steps included in the ***Energy Action Plan*** is to ensure that natural gas supply is reliable, that prices are reasonable and stable, and that energy policies and strategies that are implemented protect the environment and consumers in the state.

From an overall market perspective, it is fair to assume that participants in the natural gas industry will act in a rational manner, and make their decisions on infrastructure investment and operation in a manner consistent with fundamental economic principles which may produce short-term economic dislocations. For these dislocations to be resolved, regulatory policies and decisions must guide this development in a balanced and efficient manner.

Resolving operational, pricing, stability, and reliability concerns in the gas market involves oversight in several areas: demand, supply, infrastructure, and price/market. The Specific steps described in the ***Energy Action Plan*** include:

- Identifying critically needed gas transmission and storage capacity,
- Monitoring market fundamentals to catch the early-warning signs of any market power or manipulation,
- Evaluating new supply options for the state including LNG, and
- Promoting customers' use of a portfolio approach to manage supply purchases that includes longer-term contracts as a hedge against price volatility and high spot market prices.

The key issues needing immediate action, from state and federal agencies:

- Data Quality - misrepresentation and inaccurate information,
- Adequate natural gas storage capacity,
- Regulatory need for natural gas storage utilization by all customers,
- Cost effective increase in interstate and intrastate pipeline capacity serving the state and neighboring regions,
- Access to new and competitive natural gas supplies, including LNG,

- Need for portfolio approach including longer-term natural gas contracts to complement the volatile nature of the market,
- Increased conservation and improved efficiency at the supply and demand side of natural gas markets,
- Evaluation of the need for a back-up fuel capability and available alternatives,
- Risk identification, assessment, and analysis, including market power issues, and utilization of financial instruments.

## Data Quality - Misrepresentation and Distortion of Data in the Market Place

A major issue that surfaced following the energy crisis relates to the accuracy of data provided by market participants to the various data reporting entities. False data, previously reported in the market indices have led to a destruction of the credibility of the entire energy industry. Accusations and corrective actions have resulted in closing down many trading groups, while other companies have stopped reporting the information. Accuracy, timeliness and completeness problems have surfaced in the Energy Information and Administration's process of collecting and disseminating supply and demand information. As a result the national supply, demand and pricing information on natural gas is neither timely nor reliable enough to support fully informed market decisions.

The Federal Energy Regulatory Commission has issued voluntary guidelines that trading organizations must follow when they report information to pricing indexes. The objective is to restore confidence in such indices, which are critical in the market and used to help peg the price of natural gas. Energy companies are now voluntarily taking steps to implement corrective changes to enhance the accuracy of data supplied to reporting institutions. These new rules will provide guidance in gathering information about natural gas trades, establish a code of conduct for traders as well as a system that verifies the authenticity of the data they receive.

EIA is attempting to correct the imbalances in information on supply and demand through better verification and review processes to ensure that the quality of data is not compromised. Further, EIA is also working toward enhancing the credibility of its reports on storage activities throughout the U.S. This process will increase the confidence of the gas market and help decision-makers and market participants in reaching correct conclusions and implementing efficient decisions in the market. State agencies should continue to refine their data gathering and analytical procedures to ensure that accurate and timely information will be available to decision makers and industry participants to make balanced decisions and the right choices.

## Adequate Natural Gas Storage Capacity

Given the benefits offered by stored natural gas in terms of price stability and supply reliability, the State should investigate impacts of having more storage capacity, especially in the Southern California region. Further, privately-owned storage facilities would provide the needed supply to balance the needs of the non-core customers including industrial and power generation customers. Analysis is needed on how much storage capacity is needed, and where the storage facilities should be located.

### Gas Storage as a Tool for Managing Price Risk

Utilities (both gas utilities and electric utilities that own or buy gas-fired generation) and non-utility generators[23] currently use storage as a tool for mitigating price risk. Storage reduces the cost impacts of high spot market prices by lessening the need for the buyer to purchase on the spot market. This reduced dependency on the spot market also reduces the likelihood of the price spikes themselves.

As storage is costly, its mere availability does not always result in stable natural gas prices. In 2000, for example, high prices in the spring for fall and winter delivery discouraged storage during the summer by non-utility generators. As a result, increased demand for gas by these generators during the following winter led to even higher spot market prices than would otherwise have been the case.

Price volatility in the natural gas market can be influenced by imposing storage requirements, but this is not without cost. First, storage itself is costly, and is only undertaken when current prices are sufficiently below forward prices to justify the expense. Second, requiring storage may result in higher current prices. Mandating threshold storage levels during April – October can ensure that post-summer storage targets are met. This would reduce the likelihood of high prices during the winter heating season. If the demand for gas during the summer is high, however (*e.g.*, due to poor hydroelectric conditions requiring more gas-fired generation), this mandate may lead to substantially higher natural gas prices during the summer, which, in turn, will increase the spot market price for electricity.

Any storage requirement would have to be responsive to market conditions and, arguably, be applied to all buyers. Requiring only buyers for one class of customers to meet minimum storage requirements results in those customers subsidizing the cost of risk reduction for other consumers.

### Regulatory Need for Natural Gas Storage Utilization by All Customers

Natural gas storage operations and costs have been unbundled in the California gas market. The core customer continues to receive a bundled rate. Storage costs are rolled in with other rate-based services provided by the utility companies, such as procurement and distribution.

The noncore customers, on the other hand, have the liberty to use and pay for storage facilities, if and when they use the facilities. This provides a significant flexibility to these customers in controlling costs, but the same customers will be stranded under tight market conditions if they did not implement an appropriate storage program. Hence the policy question that arises is whether the state should implement some regulatory program through which all consumers should be required to maintain some storage. The influence of storage on supply, demand and price needs to be addressed from a seasonal approach as well as from a daily balancing function in mitigating excessive volatility and price spikes.

There is inadequate evidence at this time to suggest mandating storage for noncore customers. Over the next year, the state should investigate if appropriate storage can be used by all customers to ensure reliable and reasonable prices of natural supplies under most market conditions. The state should answer these questions:

- Who should use storage capacity, and who is responsible for actions to ensure use of the capacity?
- Does the current market structure allow some customers to “lean on” the storage paid for by others?
- Are there any barriers that prevent proper operation of private and utility owned storage?
- What are the costs and related allocation issues of using utilities’ storage for their end-use customers, and non-utility merchant generators and customers?

## Cost Effective Increase in Interstate and Intrastate Pipeline Capacity

Interstate and intrastate transportation pipelines form the critical grid needed to bring gas to end-use customers. The amount of gas used by customers varies between seasons, as well as during each day. Hence the pipeline system has to be adequate to meet this variation in the level of consumption. It is certainly not economical for pipelines alone to meet 100 percent of consumption, 100 percent of the time. There is a minimum need for storage facilities, and a need to use that storage when gas demand is low, so that combined supplies from pipelines and storage facilities are sufficient to meet the customers’ needs when gas demand is high. The Energy Commission continually evaluates the system serving the state and identify the bottlenecks and problem-areas so that supply adequacy will be maintained at all times. Adequate supply can be maintained in a variety of ways without going into the phase of forced curtailments. This includes sufficient pipeline capacity, ability to withdraw from storage, and customer's options to voluntarily not use natural gas under tight supply conditions.

Recent infrastructure expansions in California provide sufficient slack capacity to weather a tight market situation. This is very similar to the conditions that existed during the early 1990s when the Kern River, PG&E-GTN and the Mojave pipelines were constructed. Currently, Southern California has adequate capacity to meet the region’s needs under assumed demand projections over the forecast horizon. Northern California, on the other hand, will require additional capacity by about 2006 to 2007 when projected growth in demand begins to strain the system under seasonal and short-term durations.

The state should assess short-term and peaking conditions to determine the adequacy of the intrastate distribution system. The state should also evaluate the complementary aspects of utility owned distribution systems and private or interstate pipelines serving in-state customers. Further, the state should evaluate the status of the natural gas gathering pipelines to enhance the ability to transport supplies to meet all areas of need even on peak days.

## Access to New and Competitive Natural Gas Supplies

Natural gas prices are determined by achieving a balance between supply availability and quantity demanded. In a growing market, with increased demand for natural gas as a premium fuel, it is essential to ensure that there is an adequate amount of supply that can be drawn in and distributed to consumers. To achieve the goal of reasonable and stable prices, the market needs to ensure that there is a portfolio of supplies available to mitigate spiking prices.

California has been depending on three sources for its natural gas supply in addition to local production, namely the San Juan, Rocky Mountain and Canadian basins. Natural gas markets have taken a different turn since 2000, after a decade or so of relatively stable and low prices. Market perspectives now indicate that natural gas production from these regions will be available, but it will cost more than what has been paid in the past. In order to reverse or reduce the price impact, it will be necessary to find new or alternative sources of supply. The state needs to ensure that markets have the choice, ability and assurance of bringing new gas supplies to the marketplace. New sources of supply include:

- Increased exploration, development and production of natural gas inside the state,
- Access to the resources along the U.S. West Coast offshore basins, and
- Import of LNG along the West Coast.

Accessing the global LNG market will provide a significant new source of supply to the state. However, acceptance of LNG as a reliable, safe and environmentally clean fuel source by all stakeholders is important. Building the terminal facility to import LNG requires evaluation of a variety of factors such as environmental issues, safety concerns, socio-economic feasibility and public acceptance. A coordinated approach by State and federal agencies is required to ensure that siting and permitting of LNG facilities is conducted efficiently, including meeting the necessary economics, safety and environmental requirements.

## Portfolio Supplies Including Longer-term Natural Gas Contracts

Long-term contracts were conventional during the regulated era. Long-term contracts of as much as 20 years were normal. However, the competitive markets have led to significant changes. Now, long-term contracts refer to time slices of a few years. The majority of supply purchases is now done on a short-term contractual basis, or on the daily spot market. This arrangement was beneficial when a natural gas supply bubble existed and plenty of natural gas was immediately available to meet the needs in the spot markets. The current market is experiencing a new paradigm where supplies are unable to reach the market at a very fast pace. It is more expensive to produce the gas, and it takes longer to get that same quantity of gas to markets than it did in the past years. This has put a tremendous strain on the industry, resulting in either tight markets or spiking prices. The mentality of relying only on short-term supplies takes away the incentive from producers to develop resources that guarantee supplies over a longer period.

A portfolio approach should be taken to ensure reliable supply availability at all times. Utilities and private consumers must evaluate an appropriate level of short and longer-term contracts to ensure a level of supply that does not strain the financial existence of the entity. While the historical 20-year contracts may not be the answer today, a portfolio of supply options should provide a buffer against volatile and spiking price conditions. State agencies and industry participants should evaluate the options available to develop a sustainable portfolio approach that provides reliable supply options to the users while also maintaining the competitive market structure that we have found beneficial in the past.

## Increased Conservation and Improved Efficiency

Efficiency improvements have played a significant role in energy production, transportation and consumption. With continuing development and technological advancements, efficiency improvements will continue into the foreseeable future. Conservation measures have been successful in the past, during times of crisis and also during periods of normalacy. It is essential that in order to effectively utilize limited resources, enjoy the benefits accrued through energy use, and ensure a clean environment, conservation and efficiency improvements be made continuously and on each energy front to achieve a balanced use. It is essential to not only promote increased efficiency in natural gas use but also in electricity use. With increased efficiency in electricity generation and consumption, any reduction in natural gas use will enhance the reliability of gas supplies to other customers.

## Back-up Fuel Capability

Back-up fuel capability is needed if the conventionally used fuel is not available at any given time. If natural gas supplies are short or too expensive, some consumers must be able to switch from gas to an alternative source to continue meeting the consumer's energy needs. In most cases, industrial and power generation customers need the ability to switch fuels the most. During peak winter days, for example, increased use of gas by the core customers for space heating could cause a tightness in supplies, leading power generation or industrial customers with a need to switch to an alternative fuel. Fuel switching is most important to ensure reliability during supply shortages, but it could also be used as an economic tool to minimize costs by taking advantage of a cheaper alternative fuel, as long as compliance with all environmental regulations is maintained.

The state should examine alternatives to facing gas supply shortages and spiking prices. Experience from the two crisis periods of winter of 2000 and 2003 demonstrates why an escape route should be provided to customers under harsh price and supply conditions. Use of oil is not an alternative for reasons of air quality. The state should evaluate other alternatives, such as using LNG, propane or other fuels as a back-up option at the end-user facility. Other alternatives include: adding additional storage facilities at regional locations to supplement pipeline supplies with storage supplies, using distributed generation as an option to spiking electricity prices or supply shortages, and increasing use of renewable sources of fuels to complement natural gas supplies.

# Electric Transmission Infrastructure and Markets

Transmission system planners currently estimate that it takes five to seven years to complete a major upgrade to the bulk transmission system. Demonstrating need, securing environmental permits and rights-of-way, securing financing (for private projects), and time requirements for construction, require that planners anticipate the need for transmission expansion projects ten years and longer before these projects are in service. In California obstacles to timely transmission development are most commonly related to debates over project benefits and the need for the project, project financing difficulties and local opposition related to environmental and property value impacts. These obstacles arise because:

- Permit processes for the various types of transmission projects are fragmented and overlapping and environmental analyses are inconsistent.

- Total project benefits are not adequately addressed in the permitting process. Economic benefits and costs of projects requiring a Certificate of Public Convenience and Necessity must be viewed by the CPUC in the context of ratepayer benefits only. Therefore, statewide strategic benefits from a project may not be adequately addressed.

- The planning process may address issues important to individual transmission owners and CA ISO, but may overlook issues that are vital to broader interests, such as future right-of-way needs, more efficient use of the existing system, the environmental performance of the system, and the need for long term statewide strategic expansion of the system. As a result, projects with broad economic benefits may face opposition in permitting. They are not considered in the context of broader, long term transmission planning including project alternatives. Investor-owned utility and merchant transmission line developers may propose economic projects for consideration in the CA ISO process. Publicly owned utilities and federal agencies, for the most part, propose, plan, and build transmission projects to meet their own reliability and economic needs. Consequently, coordination among entities needing transmission may not occur and broader benefits of coordination are lost.

- Private investment in transmission, although encouraged by FERC, has been slowed by the financial distress of some developers, as well as regulatory and economic uncertainty.

- Potential adverse effects from system expansion are usually local and concentrated, whereas the benefits are normally diffuse and regional or statewide in nature. It is difficult to balance the larger public interest with legitimate concerns on the part local citizens and local opposition to some projects.

The June 12, 2003 Joint Energy Commission and League of Women Voters workshop has helped to focus on public opposition as a significant input to the planning and expansion of the transmission system. Public opposition to the construction of new transmission is considered one of the most common and serious impediments to transmission system expansion in California and therefore an important consideration in the transmission system planning process. Because of the length and linear nature of transmission expansion projects, new transmission lines, even those proposed in existing corridors set aside for transmission development can experience serious local opposition. Public opposition is usually related to visual and aesthetic affects, land use conflicts, and potential economic impacts such as reduced property values. In addition, many transmission line projects have generated significant opposition from the public due to concerns about adverse impacts to public health from electromagnetic fields (EMF).

The consensus view emerging from the workshop was that public opposition to transmission expansion is tied to a lack of information and understanding of the transmission planning process, costs and benefits of expansion projects, and whether and to what degree alternatives such as generation, demand-side management (DSM) and alternative routes are considered. To address this problem, workshop participants suggested the need for better forums for public involvement in transmission planning and improved actions to mitigate community impacts from planned projects. Another view was also expressed that it is oftentimes difficult to get the public interested in transmission planning issues, perhaps even with the best educational and information programs.

The staff realizes that not all public opposition can be overcome. However, the staff feels that the process can represent the public interest and result in a quality decision. If the public understand its benefits and costs, the alternatives that were considered, why the project is considered needed for broader state or regional benefits, that community impacts were mitigated, and that the process was objective and provided opportunity for their involvement.

## Actions Underway to Resolve Issues

Over the past decade a number of recommendations have been made by various organizations to address California's obstacles to realizing needed transmission system expansion. Actions have been taken most recently by state government, the CAISO and others to remove obstacles and ensure that the permitting and planning processes for transmission projects are coordinated and effective in addressing issues related to project benefits and costs. The most noteworthy of these recent actions are briefly discussed below.

### Implementing the State *Energy Action Plan*

The 2003 State Energy Action Plan is a collaborative effort among the CPUC, Energy Commission and CPA. One goal of the plan is to ensure that the state will invigorate its planning, permitting and funding processes to ensure necessary expansions to the bulk transmission system are undertaken in a timely manner. In the plan, the state is committed to assure that necessary improvements and expansions to the distribution and bulk electricity grid are made on a timely basis. The above agencies will collaborate in partnership with other state, local and non-governmental agencies with energy responsibilities to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California's electricity users.

### Implementing SB 1389

The Integrated Energy Policy Report (IEPR) process was initiated in 2002 by the Energy Commission to carry out the mandates of SB1389. The current IEPR process identifies transmission system expansion needs, and makes state findings on the benefits of proposed transmission projects that can be used by decision makers in the permitting process.

To that end, staff analyzed four representative transmission projects in this IEPR cycle: (1) a major interstate project proposed for economic reasons; (2) a major intrastate, inter-utility project proposed to address local reliability needs; (3) an intra-utility project proposed to address local reliability needs; and (4) an intra-utility project proposed to address existing and likely future Renewable Portfolio Standard needs. In addition, the selected projects are ones that are of immediate concern to staff because they will (or do) require a Certificate of Public Convenience and Necessity (CPCN) from the CPUC; their ability to obtain a CPCN has been denied or is not yet certain; and staff believes that these projects could benefit from a timely analysis of strategic benefits beyond those analyzed in the current CPCN process.

For each project, staff conducted a preliminary economic and/or reliability analysis to assess potential benefits and identify potential critical issues. The results of staff's analysis are included in a staff report entitled ***Upgrading California's Electric Transmission System: Issues and Actions*** which will be released shortly after the ***Staff Draft Electricity and Natural Gas Assessment Report*.**

As noted above, one of the obstacles to encouraging private investment in electricity transmission system expansion is regulatory uncertainty. The state's actions related to transmission improvements are also intended to address reducing regulatory uncertainty for project proponents while ensuring that the planning and permitting processes are transparent to all interested parties.

## Developing Common Methods and Long-Term Planning

An effort is underway on the part of the CA ISO and CPUC to develop a common approach to be used in the planning and permitting of transmission projects to determine the value of proposed projects that may be needed to provide economic benefits to the state.

A separate effort is being initiated by the Energy Commission and CA ISO which is intended to ensure that long term planning and strategic project benefits are included in the CA ISO transmission planning process and state IEPR process, and appropriately considered in the state's permitting process for bulk transmission system expansion.

## Coordination Among Actions

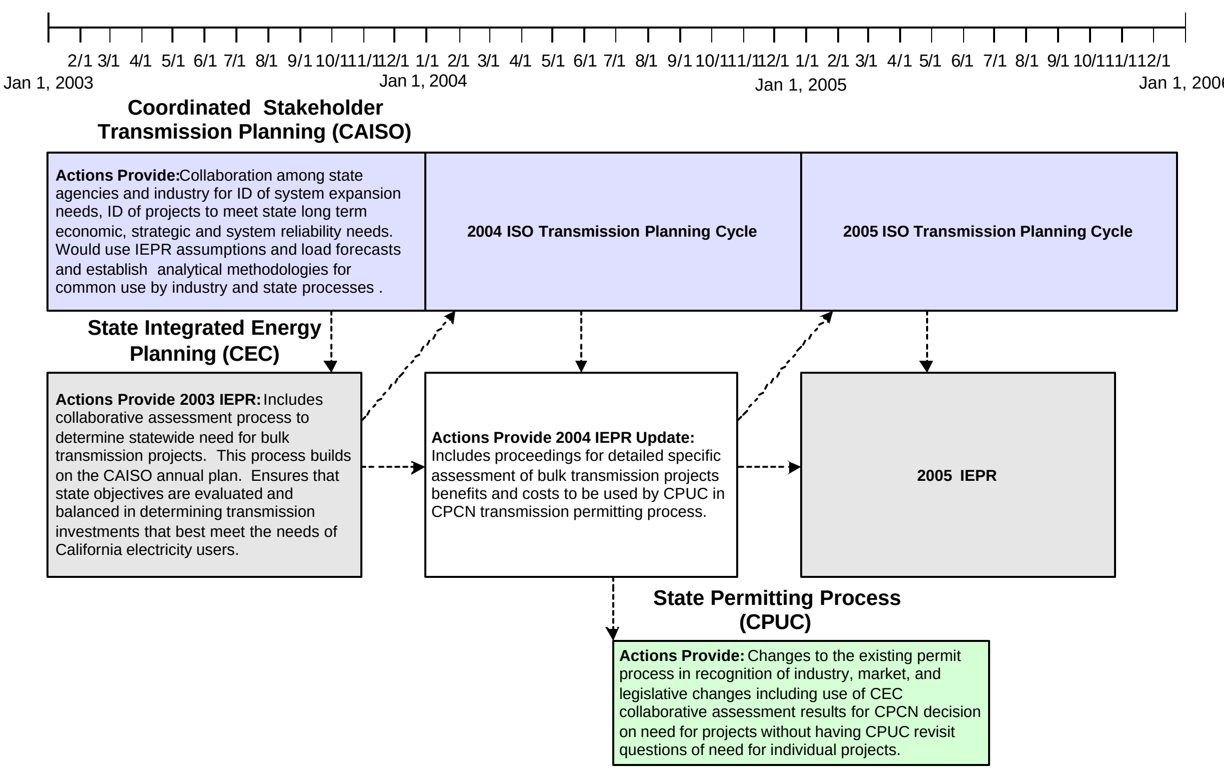
The above actions represent legislation and agency coordination agreements being implemented by governmental and nongovernmental agencies to ensure that the most crucial energy issues facing California can be addressed in the near term. Energy Commission staff believe that the most crucial problem to solve from an electricity transmission perspective is the reinvigorating of the state's transmission planning and permitting processes to assure that necessary expansion to the bulk transmission system can be made on a timely basis. None of the above actions, standing alone, will assure necessary expansions on a timely basis. However, working together, the synergistic effects of these actions can resolve the problem. Whether or not the problem gets adequate resolution will depend in large part on the degree of cooperation realized among the key agencies. For example, it will be essential to the success of the State Energy Action Plan that the Energy Commission, CAISO and the CPUC recognize each other's responsibilities and collaborate effectively towards solutions to questions of transmission project need and timely permitting of transmission projects.

The synergies among the actions for which these agencies are responsible are shown on **Figure 6-1.** As shown, these actions working together make it is very feasible to take a project originating in the CA ISO coordinated stakeholder transmission planning process, to the state permitting process with the basis for a need determination completed in the IEPR or IEPR Update, within about 18 months. With appropriate changes implemented for the CPUC CPCN process, that process will not re-visit questions of need for certifying individual projects. The CPCN process will use the IEPR Update need assessment as a basis for its need determination and focus its efforts on the CEQA requirements for permitting. This will represent a major efficiency improvement in the planning and permitting of bulk transmission projects and bring the state much closer to effectively addressing the crucial issue of timely permitting for transmission projects.

Other synergies among the actions result from the CA ISO improving their transmission planning process to include longer-term transmission planning, valuing the strategic benefits of transmission projects, and developing analytical methodologies for common use by industry and state planning and permitting processes. The effects of these actions are to provide a more complete perspective of the value of individual planned transmission projects and reduce regulatory uncertainty.

With respect to public opposition to transmission projects, an additional action is identified by staff that could be pursued as a result of the League of Women Voters efforts. This action could be pursued during the 2004 IEPR Update and may help to give a better basis for considering public opposition to system expansion. First, staff could develop information on existing forums for public awareness and participation in transmission system planning, including right of way planning and local agency processes. Second, staff could identify the most effective and efficient methods to implement public participation in the context of the IEPR process and the Energy Action Plan, and ensure that community impacts associated with transmission expansion are appropriately considered in both the IEPR process and the CA ISO transmission planning process.

**Figure 6-1**
**Synergies of Actions for Overcoming Transmission Issues**



# Endnotes

[1] "California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study", Study ID #Sw039a, Prepared For Pacific Gas & Electric Company San Francisco, California, Prepared By Principal Investigators Fred Coito And Mike Rufo, XENERGY Inc., Oakland, California. "California Statewide Residential Sector Energy Efficiency Potential Study, Study" ID #SW063, Prepared for Pacific Gas & Electric Company. Prepared by Principal Investigator Fred Coito and Mike Rufo, KEMA-XENERGY Inc., Oakland, California, April 2003. "California's Secret Energy Surplus", Prepared for The Energy Foundation and The Hewlett Foundation, Prepared by Principal Investigators Fred Coito and Mike Rufo, XENERGY Inc., September 23, 2002.

[2] In addition, roughly 6,000 MW of capacity meets "self-generation" needs on a regular, occasional or emergency basis.

[3] http://www.energy.ca.gov/electricity/2003_SUPPLY_DEMAND_PEAK.PDF

[4] In addition to reflecting the cost of real-time purchases, spot market prices serve the following functions:

- Spot market prices establish the real-time benchmark against which capacity is dispatched. If spot market prices are low relative to the cost of generation using a particular physical asset (*e.g.*, a utility-owned power plant) or option thereon (*e.g.*, a dispatchable contract), the owner will purchase spot market energy rather than dispatch the power plant/contract.
- Spot market prices provide a signal of the need for new capacity. High spot market prices relative to production costs indicate that new power plants will be profitable. In the absence of relatively high anticipated spot market prices ("forward prices"), new capacity will not be forthcoming without a long-term contract.
- Spot market prices indicate that generators are exercising market power. If the market is clearing at prices not warranted by production or opportunity costs, this may be a sign that generators are able to sustain prices at non-competitive levels.

[5] See, for example, the *2002 Annual Report on Market Issues and Performance* (CAISO, April, 2003): "the short-term energy market in California has stabilized and produced fairly competitive results during [2002] (p. E-10)"

[6] Averaged prices are derived by taking the mid-points of the range of prices for each day, then using an (unweighted) average of these points. In those few instances where separate peak and off-peak prices were not available, the single average price derived was assumed to represent both the peak and off-peak price.

[7] See Frank Wolak, Lessons from the California Electricity Crisis, CSEM working paper #110, April 2003

[8] The amount of capacity necessary will be reduced on a MW-for-MW basis to the extent that new demand-side programs can be used to reduce capacity needs.

[10] More detailed information regarding the assumptions underlying each of the scenarios can be found in the Technical Appendices to this report.

[11] Staff also developed a scenario in which PGC funding is reduced, resulting in less DSM savings and renewable capacity and energy. The assumptions underlying this scenario and detailed results for all three scenarios can be found in the Technical Appendixes.

[12] This information is current as of July 10, 2003.

[13] CATIC used a modified Special Operations Forces Intelligence and Electronic Warfare Operations plan called CARVER after the factors: Criticality, Accessibility, Recuperability, Vulnerability, Effect, and Recognizability Factors.

[14] Natural Gas Market Assessment, California Energy Commission, August 2003, publication 100-03-006.

[15] The Wild Goose Storage facility is expanding its facility, with Working Gas Capacity increasing to 29 Bcf, maximum injection capacity to 450 MMcf/d, and maximum withdrawal rate to 700 MMcf/d.

[16] 2003 EPR, pages 7 and 8

[17] Source: EIA database "Current and Historic Monthly Sales, Revenues, and Average Revenues per kWh by State and Sector and Energy Commission QFER database.

[18] Cost examples provided in **Figure 8** are based on the average of spot market transactions at the San Juan Basin to Topock, Arizona on October 4, 2002. The gathering and conditioning charge is based on various publications from the U.S. Department of Energy, Energy Information Administration (EIA). The transportation charge is the price of transporting natural gas from the San Juan Basin to the California border at Topock, Arizona.

[19] Analysis of $NO_x$ emissions for this report has focused on the swing facilities, so information on the trends for the baseload facilities is not presented here. The baseload facilities were not undergoing significant retrofit during this period, so their emission rates are unlikely to have changed significantly. Because their electricity generation was also relatively constant, their total emissions are believed to have remained relatively steady during this period. Data collected for the cogeneration and base load units are inconsistent and are not presented here.

[20] Practicable is defined as available and capable of being done after taking into consideration, cost, existing technology and logistics in light of overall project purpose.

[21] *Joint Working Paper on Resource Adequacy*, prepared by Energy Commission and California Municipal Utilities Association, July 1, 2003, IEPR Docket.

[23] Gas procurement is undertaken by gas utilities for "core" customers, primarily residential and smaller commercial consumers. Electric generators and other large consumers are "non-core," and are responsible for securing their own gas supplies and any necessary interstate transmission (pipeline) capacity, either directly or through marketers.